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COMPETITION TO SERVE NORTHEAST NATURAL GAS MARKETS

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

SECOND SESSION

ON THE

COMPETITION TO SERVE NORTHEAST NATURAL GAS MARKETS

MAY 3, 1990

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COMPETITION TO SERVE NORTHEAST NATURAL GAS MARKETS

THURSDAY, MAY 3, 1990

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 9:35 a.m., in room SD-366, Dirksen Senate Office Building, Hon. J. Bennett Johnston, chairman, presiding.

OPENING STATEMENT OF HON. J. BENNETT JOHNSTON, U.S. SENATOR FROM LOUISIANA

The CHAIRMAN. Good morning. Today, the Committee on Energy and Natural Resources will examine the issues surrounding applications to serve the markets in the Northeast with Canadian natural gas.

The Federal Energy Regulatory Commission has pending before it an application for a certificate to construct a major new pipeline to transport Canadian gas to the Northeast. The Department of Energy has already granted conditional authority to import Canadian natural gas that will be transported by the proposed pipeline.

Independent natural gas producers in the United States allege that they will be competitively disadvantaged by the Canadian imports. The domestic producers do not oppose competition with Canadian producers when it is on a level playing field, but they do oppose this particular import arrangement because of the way it has been structured. According to the independents, the import deal gives Canadian producers an unfair competitive advantage over domestic producers.

The independent producers' argument goes like this: compared to American pipelines that are regulated by the FERC, Canadian pipelines are permitted to recover a greater percentage of their cost in the demand charge. A demand charge is like a reservation fee which the pipeline collects regardless of how much gas is actually transported or sold.

When the demand charge is high, the commodity charge, which is collected on the basis of how much gas is actually transported or sold, can be very low. Since the demand charge is a sunk cost, customers faced with competing sources of gas will make their choice based on who has the lowest commodity charge. In this way, natural gas transported by a Canadian pipeline has a competitive advantage over gas transported by an American pipeline.

Also under this deal, the Canadian producers are selling their gas directly to American customers rather than through an American pipeline. Finally, the import deal is set up so that American customers pay for both the Canadian gas and the Canadian pipeline transportation north of the border. This way, these parts of the deal are beyond the jurisdiction of FERC.

I thought we had already dealt with this problem when the Congress ratified the U.S.-Canada Free Trade Agreement. The FTA, as it is called, affected many aspects of national energy policy, including natural gas. As this Committee will recall, I approached the FTA with a good deal of skepticism. Other members of this Committee shared my skepticism. We feared that the FTA would give Canadian producers an advantage at the expense of domestic producers.

The Energy Committee held hearings on the FTA. In connection with these hearings the Energy Committee received assurances that FERC's Opinion Number 256, the so-called "as-billed" decision, would not be overturned by the FTA. We received assurances from Canada's Ambassador to the United States. We received assurances from the U.S. Trade Representative. We received assurances from the U.S. Department of Energy. We received assurances from the Chairman of the Federal Energy Regulatory Commission.

Opinion 256, you may recall, required that costs associated with Canadian natural gas receive the same rate treatment as domestic gas cost when recovered in the rates charged by American pipelines.

In my view, the principles of Opinion 256 should apply to the import deal that is the topic of today's hearing.

There must be a way for the FERC and DOE to level the playing field. U.S. and Canadian producers should compete on the basis of the price of gas, instead of the complexities of pipeline rate design.

Unfortunately, it appears that neither the FERC nor DOE share my view. In its order conditionally approving the Canadian imports, DOE held that Opinion 256 is not directly applicable to the case. DOE also rejected arguments that the disparity between the U.S. and Canadian pipeline rate regulation makes the proposed import deal uncompetitive.

FERC made its views known in the so-called "Niagara Spur" order. FERC held that Opinion 256 was limited to a pipeline's recovery of Canadian gas cost in its sales rates. FERC added that concerns about the disparity of U.S. and Canadian pipeline rate design could be addressed in the context of individual pipelines' rate cases.

If that is the law, perhaps the Congress needs to change the law. Either that, or perhaps DOE and FERC can explain to me how we can get a level playing field for domestic and Canadian producers under the existing law.

I want to make clear that the Committee is sensitive to the fact that this hearing deals with matters that are pending before FERC and DOE. By this hearing, the Committee is not telling the agencies how to decide these cases on the merits. These are decisions that the Congress has entrusted to FERC and to DOE.

We do want to make sure, however, that the agencies are properly discharging their responsibilities under the Natural Gas Act. This means giving the proper weight to allegations raised by intervenors. It also means ensuring that all factors bearing on the public interest are reflected in the agencies' orders.

I fully appreciate the need to expedite consideration of applications to construct new pipeline facilities and render new natural gas service. I am aware that in the past a number of proposed pipeline projects have vanished between the procedural quicksand at 825 North Capitol Street. For that reason, I have applauded the Commission's efforts to expedite the consideration of pipeline certificate applications.

I am also fully aware of the energy situation in the Northeast. A little over a year ago this Committee held an oversight hearing regarding electricity supply and demand in the Northeast. The Committee does not intend to do anything that would exacerbate the Northeast's difficulties.

All of this, however, does not relieve the Commission of its responsibilities under the Natural Gas Act. A settlement among the sponsors of competing pipeline projects is not the same as a finding that the project is in the public convenience and necessity. Under the Natural Gas Act, only the Commission can make that finding. It is a finding that must be made following a careful review of the record of the certificate proceeding.

This is Chairman Allday's first appearance before the Committee since his confirmation last November. On behalf of the Committee, I welcome the Chairman back. So far, he has gotten rave reviews for the job he has been doing over at the Commission.

Chairman Allday, as I indicated before, the Committee is very sensitive to the fact that this hearing deals with matters pending before the Commission. Should you believe that answering a question would affect your impartiality as a decision-maker in the pending proceedings, you may of course refuse to answer. Also, I advise my colleagues on the Committee to avoid questions which may put Chairman Allday in such a position.

I have been asked by Senators McClure, Dodd and Lieberman of Connecticut to announce that they have submitted written statements for inclusion in the record of this hearing, but before getting to the Chairman's questions, I would like to yield to any of my colleagues who have opening statements. I believe Senator Bingaman was first. Senator Bingaman.

[The prepared statements of Senators McClure, Dodd, and Lieberman follow:]

STATEMENT OF HON. JAMES A. MCCLURE, U.S. SENATOR FROM IDAHO

I want to commend Senator Johnston for holding this oversight hearing. Today the Committee is focusing on efforts to bring new natural gas supplies to the Northeast, and specifically the Iroquois pipeline proposal. This issue is important both to consumers in the Northeast and to domestic gas producers, particularly independents.

Northeast consumers want new supplies of natural gas and don't seem to care where it comes from—so long as it does come, and is priced reasonably. Domestic independent producers, on the other hand, are very concerned that the Iroquois proposal, if approved by DOE and FERC in its current form, will discriminate against domestic production, thereby denying them access to new markets in the Northeast.

Central to this debate is the effect of the U.S.-Canada Free Trade Agreement, in which this Committee played a key role. Some have asserted that the Agreement ties the hands of the U.S. Government, specifically the Department of Energy and the Federal Energy Regulatory Commission, with respect to the terms and conditions of imports of Canadian gas—that is simply not true. The Senate Report accompanying the Act approving the Agreement specifically notes that:

> Sections 4 and 5 of the Natural Gas Act require rates and charges for interstate transportation of natural gas to be "just and reasonable" . . . and not "unduly discriminatory, or preferential. . . .

And further that:

> . . . the Agreement does not in any way affect the ability of the U.S. regulatory authorities, including ERA and FERC, to impose appropriate terms and conditions on imports and exports of natural gas under the Natural Gas Act. The Committee sought, and received, assurances that nothing in the Agreement alters, supplants, or preempts the mandate of the Natural Gas Act or the Natural Gas Policy Act of 1978.

Thus, while the Free Trade Agreement does stand for the principle that the U.S. Government can not discriminate against Canadian natural gas, the Agreement does not prevent the United States from placing terms or conditions on imports of Canadian gas which mitigate potential discrimination against U.S. production. I do not know if the terms and conditions under which Iroquois is proposing to import gas do, in fact, discriminate against domestic production, but I understand that that is one key concern of the IPAA which is testifying here today.

I look forward to hearing from today's witnesses to gain a better understanding of their concerns and perspectives on associated issues. I also want to take this opportunity to welcome FERC Chairman Allday at his first appearance before this Committee since his confirmation, and to commend him on his efforts to date at the Commission.

STATEMENT OF HON. CHRISTOPHER J. DODD, U.S. SENATOR FROM CONNECTICUT

As a member of the Connecticut Congressional delegation, I have closely followed the consideration by the Federal Energy Regulatory Commission of the Iroquois Gas Transmission proposal to transport Canadian natural gas to the Northeast in general and Connecticut in particular.

Throughout the Northeast Natural Gas Markets Proceeding, my paramount concern has been the FERC ensure protection of the due process rights of all interested parties, including those outside the natural gas industry, as it considers the Iroquois Gas Transmission System application for a certificate of public convenience and necessity. In fact, over a year ago, on March 14, 1989, along with Senator Bill Bradley of New Jersey, I wrote then Chairman Martha Hesse of FERC, urging the Commission to set the issue of public convenience and necessity for an evidentiary hearing before an administrative law judge.

Chairman Hesse's response to my letter included a pledge that "the merits of all the public interest issues, including the firmness of supply and demand, the viability of alternatives, and environment and rates will be fully addressed during the proceedings on each certificate application. During these proceedings, each party will have ample opportunity to participate in the formulation and resolution of issues and to present its case."

I am aware that a number of intervenors in this case, including several from the State of Connecticut, have filed motions, asking that the Iroquois certificate application be set for evidentiary hearing. According to these intervenors, a full evidentiary hearing is necessary in order to produce substantial evidence on a variety of material issues of fact involving the proposed Iroquois pipeline, transportation services and rates for such services. Market need, facilities sizing, and the implications for consumers and producers that may result from Iroquois are among the concerns often expressed by intervenors. Moreover, several of my Connecticut constituents have expressed serious concerns relating to the adequacy of the FERC review of potentially adverse environmental impact.

I understand that the Commission has not yet acted on intervenors' motions to set the Iroquois proceeding for an evidentiary hearing. It is my hope that when the Commission next considers the Iroquois proposal, all of the information and concerns submitted by intervenors will be thoroughly analyzed by the Commission in order to determine whether the case can be appropriately resolved on the basis of the written record or whether further proceedings are needed.

The desire for prompt resolution of the Iroquois matter must be reconciled with the necessity of protecting the due process rights of all participants in these proceedings. It is my hope that the Commission will comply with its statutory duty under the Natural Gas Act and will act consistently with former Chairman Hesse's pledge that all interested parties will be allowed full and fair opportunity to present their cases on the merits of the Iroquois certificate application.

STATEMENT OF HON. JOSEPH I. LIEBERMAN, U.S. SENATOR FROM CONNECTICUT

Mr. Chairman, Members of the Committee, I appreciate this opportunity to testify before the Committee on Energy and Natural Resources with regard to plans to import Canadian natural gas to serve markets in the Northeastern United States. As a public official and lifelong resident of Connecticut I am very concerned about the availability and cost of energy supplies for my state and region. I have been particularly concerned about the dramatic fuel price increases of last winter.

The application of the Iroquois Gas Transmission System for a certificate of convenience and necessity from the Federal Energy Regulatory Commission is, of course, related to those problems. I have been involved in the issues surrounding the Iroquois pipeline since my days as Attorney General for the State of Connecticut.

Concern in my state about the pipeline has focused on two particular questions.

(1) Is the construction of this pipeline the most appropriate and effective way to address the current and future energy needs of Connecticut and other Northeastern states?

(2) Has the planning process for the pipeline thoroughly responded to the environmental, economic and community interests of the Connecticut citizens most directly effected by the proposed pipeline?

I regret to say that, from a Connecticut perspective, FERC's regulatory review process for the proposed pipeline has not satisfactorily answered either of these questions. My testimony addresses two ways that FERC can improve the planning process for the Iroquois pipeline. First, FERC could order an evidentiary hearing on all aspects of the pipeline. Second, FERC could use Environmental Impact Statement process more aggressively to examine alternative solutions to Northeastern energy supply issues.

I believe the best way to determine whether the pipeline is a preferable solution to Connecticut energy needs is to hold an evidentiary hearing on the proposed pipeline.

Since the announcement of the proposed Iroquois Pipeline, the State of Connecticut has repeatedly requested an evidentiary hearing. At the technical conference on November 20, 1989 they renewed the request for a evidentiary hearing. A full evidentiary hearing is the best mechanism to examine issues of rate design, cost of capital and capital structure among others.

It is my understanding that FERC has not ordered such a hearing and apparently has no intention of doing so. This is regrettable. While it is FERC's decision to make, the failure to order such a hearing demonstrates insensitivity to citizens and officials of Connecticut. If the proposed pipeline is built, its neighbors will never know whether it is the best solution to regional energy problems.

While it is not the primary focus of this hearing, I am also concerned about the environmental implications of the proposed pipeline. FERC has released a Draft Environmental Impact Statement (DEIS). Many of the comments I have seen, including those of the Environmental Protection Agency and the Fish and Wildlife Service, suggest that the DEIS is seriously deficient. While the comments do not identify any single major environmental problem, they suggest that the data provided in the DEIS is inadequate for making such a judgment. There are many people in Connecticut who feel the route selected by Iroquois unnecessarily affected sensitive wetlands and forests.

For three years, the public has been identifying the FERC and Iroquois sensitive areas that should be avoided for environmental and socioeconomic reasons. Some routing variations may minimize the environmental and socioeconomic damage that would be caused by the pipeline, yet FERC has not required that they receive full review, either in the DEIS or by Iroquois. Rather than using the alternative process of the DEIS affirmatively to develop route variations that avoid these areas, I believe FERC has relied too much on route variations specifically proposed or developed by Iroquois. In previous communications with the Commission, I, along with Congresswoman Johnson and Congressman Rowland, have suggested the Commission marshal its own considerable resources to identify optimum route variations.

In addition, some of my constituents argue that the DEIS does not adequately address some alternatives to construction of a pipeline, as required by the National Environmental Policy Act. In particular, they state that the DEIS does not examine partial solutions that could provide some, but not all, the capacity proposed by Iroquois. For example, the DEIS might consider a solution that would rely on a combination of sources, including gas from some of the Northeast projects certificated by the Commission since the Iroquois application was filed; use and expansion of some of the existing systems currently serving the Northeast; and conservation measures.

An alternative specifically relying on these sources, we are told, could provide much, if not all, of the volumes to be supplied by Iroquois without the environmental damage of a new pipeline. FERC should assure that the final EIS thoroughly examines these options as well.

In closing, Mr. Chairman, I wish to make clear that the proposed pipeline appears to be a well-intentioned attempt to supply a critical energy market. However, I also believe that the planning process should contain the fullest possible open exchange of information. This can be achieved with an evidentiary hearing on pipeline. As the responsible Federal agency, the Federal Energy Regulatory Commission should require it.

STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

Senator BINGAMAN. Thank you, Mr. Chairman. I have a very short statement which I would like to give. I do appreciate you having the hearing. I think it is very timely, very important.

I agree with you that there is a need to expedite the process of approving natural gas pipeline facilities, but of course I also share the concern you express that in doing so we need to ensure that the legal standards under the Natural Gas Act are not shortchanged.

Last year, in response to a letter from Senators Bradley and Dodd regarding the need for a hearing in the Northeast pipeline proceedings, I believe Chairman Hesse at that time gave assurances that each party would have an ample opportunity to participate in the formulation and resolution of issues.

To my mind, that means that, if they could demonstrate adequate evidence in support of their allegations, intervenors would have an adequate opportunity to present that evidence before an administrative law judge, and I certainly hope that can be the case. Intervenors in the Northeast proceedings have had a great concern, as I understand it, that their issues continue to be postponed and not brought to closure.

As for the Department of Energy, Section 3 of the Natural Gas Act would appear to establish a presumption favoring imports. I question whether the Department's laissez faire policy regarding import applications is appropriate, particularly in the case of long-term import arrangements involving substantial volumes of natural gas. I am concerned that the Department's failure to give intervenors a timely opportunity to seek rehearing and ultimately judicial review could present a problem as well.

I do think this is a timely hearing, Mr. Chairman. It is an important issue, and I look forward to the testimony.

[The prepared statement of Senator Bingaman follows:]

STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

Thank you, Mr. Chairman, for calling today's oversight hearing regarding applications before the Department of Energy and the Federal Energy Regulatory Commission to import Canadian natural gas and to construct pipeline facilities to deliver natural gas to markets in the northeastern United States.

I appreciate the need to expedite the process for the approval of new natural gas pipeline facilities. In my region of the country, there is a pressing need for expanded pipeline facilities to deliver natural gas from the Southwest to markets in California and elsewhere. The need for expedition does not mean, however, that the legal standards under the Natural Gas Act should be given short shrift.

Last year, in response to a letter from Senators Bradley and Dodd regarding the need for a hearing in the Northeast pipeline proceedings, Chairman Hesse gave her assurances that "each party will have an ample opportunity to participate in the formulation and resolution of issues and to present its case." To me, this means that if an intervenor makes an adequate demonstration of evidence in support of its allegations, an evidentiary hearing before an administrative law judge should be ordered. Ultimately, a better order on the merits will result and the Commission will be in a better position to defend its order on judicial review.

I am also concerned about what, at least on the surface, appears to be a procedural "shell game" being played by the Commission and the Department of Energy. Intervenors in the Northeast proceedings have alleged that whenever they raise an argument, the agency responds that it will be addressed in some future proceeding.

As for the Department of Energy, while section 3 of the Natural Gas Act would appear to establish a presumption favoring imports, I question whether the Department's laissez faire policy regarding import applications is appropriate, particularly in the case of long-term import arrangements involving substantial volumes of natural gas. I am also concerned about the Department's failure to give intervenors a timely opportunity to seek rehearing and ultimately judicial review of import orders. Process delayed is process denied.

I look forward to the testimony from our witnesses and I will have a number of questions to explore the points that I have raised in my opening statement.

The CHAIRMAN. Senator Bradley.

STATEMENT OF HON. BILL BRADLEY, U.S. SENATOR FROM NEW JERSEY

Senator BRADLEY. Thank you very much, Mr. Chairman.

Oversight of FERC and DOE regulation under the Natural Gas Act is clearly an important function of this Committee. However, it is also important that we exercise that authority in a manner that does not compromise or interfere with the normal functions of these agencies.

It is a very slippery slope, from my perspective, to use the Committee hearing process to influence or prejudice the decisions of agencies involved. Whether or not it is so intended, I believe that this hearing will be perceived widely as an effort to unduly influence the way FERC and DOE are handling the on-going Iroquois application. I might even go so far as to say that this hearing could very well be the subject of future legal action, and I regret it.

I wish the hearing had not taken place. I think it is a mistake. The issue of need for new supplies, rates and the so-called level playing field issue are all now before FERC for consideration. From where I sit, that is exactly where these issues, complex as they are, are best addressed—by the regulatory agencies which we ourselves have created.

If FERC and DOE had ignored a clear mandate of the Natural Gas Act, I would agree that an oversight process could serve as a useful way to remind the agency of its statutory duty, but this is not the case here. FERC has not even made a decision yet.

Now, hundreds of parties have been involved in these proceedings. I am told there are millions of pages of testimony, and clearly, given the number of people in this room, many millions of dollars have been spent.

Over a year ago, as Senator Bingaman said, I and Senator Dodd wrote the Commission and suggested there could be an expedited trial-type hearing that could have concluded before the environmental review would have been finished. Chairman Hesse assured me that all parties' perspectives would be fully considered. Surely, we are today neither ready nor able to judge the adequacy of that million-page record.

If the record is inadequate after FERC has made its decision, it is going to be the courts who are going to decide. Mr. Chairman, this project is in fact supported strongly by all the State public utility commissions that will receive the gas.

I would like to submit for the record the letter from the New Jersey State Board of Public Utilities and have that made a part of the record.

[The letter referred to follows:]

State of New Jersey,
Board of Public Utilities,
Newark, NJ, May 1, 1990.

Re May 3, 1990 Hearing on Canadian Gas.

Senator J. Bennett Johnston,
Chairman, U.S. Senate, Committee on Energy and Natural Resources, Washington, DC.

Dear Senator Johnston: I am writing with respect to the oversight hearing scheduled for May 3, 1990 to be held by the U.S. Senate Committee on Energy and Natural Resources to review the question of the importation of Canadian gas and the necessity for the construction of the Iroquois Gas Pipeline for the purpose of delivering Canadian gas to the Northeast United States.

New Jersey has long been considered part of the Northeast gas market. This State for a long time has been actively pursuing additional gas supply for an expanding residential and gas heating market, as well as for electric generation and cogeneration projects. Crucial to this quest for additional gas supply is our need for additional pipeline capacity for this region and the Northeast in general. By reason of our state's location in the Mid-Atlantic region, we are literally at the end of every pipeline serving this area.

The New Jersey Board of Public Utilities has supported expansion of the Columbia pipeline, restoration and expansion of the Texas Eastern Pipeline, additional capacity for the Transcontinental Pipeline, and new interconnections from the Tennessee Pipeline. The purpose of all of these projects was to bring additional domestic gas to the Northeast. In fact, today New Jersey's supply comes almost 100% from domestic supplies. A small amount of Canadian gas currently arrives here through the Boundary Project.

We support the Iroquois project as we have supported and will continue to support every project that has the potential of bringing additional gas to this State. New Jersey's gas utilities' supply plans continue to rely overwhelmingly on domestic gas. A review of the five-year supply plans annually filed by our local gas utilities shows most of New Jersey's additional gas supply needs will come from domestic sources, with only a relatively small percentage expected from Canada. Even including all the projected Canadian gas, New Jersey will still rely on domestic gas for 94% of its supply. But every bit of gas supply counts, especially on that cold peak winter day. I am, therefore, writing today to express our support for and to request your committee to urge the FERC to speedily approve the following gas supply projects currently awaiting final approval:

The Niagara Import Project (NIPS), which FERC orally approved on April 11, 1990.

The Texas Eastern CD-1 Project. This is domestic gas, there is no opposition, yet two years have passed since its original filing.

The Iroquois Pipeline. Iroquois will expand the supply options to the Northeast, not supplant existing supply options.

The energy needs of this State can easily accommodate all supply available to it, both domestic and Canadian. I have heard that the IPAA questions the Northeast's need for gas from Canada. Our short answer is we need gas—we need it from our traditional domestic suppliers; we need it from Canada. Indeed, the NIPS project and the Texas Eastern projects are required by this winter's peak. Iroquois is needed for next winter's peak.

The entire need question was fundamental in the Open Season proceeding conducted by FERC. No other region of the country was subjected to the intense scrutiny which the Northeast experienced. The time has now come to move the projects from the drawing board into the ground, to supply New Jersey consumers and the entire Northeast with the gas we fought so hard to get. If an additional needs assessment is required, which we challenge, then it should be done for domestic as well as Canadian gas.

A question has been raised regarding the pricing of Canadian gas. Be assured that the New Jersey Board of Public Utilities looks at the final *delivered* price of gas, not just the commodity component. We are well aware of the different pricing structures, and it is that final delivered price that determines the competitive nature of the gas, not just one part of it.

However, if there is real discrimination in pricing, if in fact there is unequal treatment on either the Canadian or U.S. side of the border, there is an avenue to resolve such disputes. The Canadian-US Free Trade Agreement (recently approved by both governments) in Article 905 provides for "direct consultation" to resolve disputes in energy matters.

I thank you for the consideration I know you will give to the energy needs of the State of New Jersey.

Sincerely,

SCOTT A. WEINER,
President.

Senator BRADLEY. That means that they believe the long-term gas purchase contracts are prudent, and I presume that you have seen the very emphatic letter that I mentioned and that you will take a look at it carefully, and I am sure the Commission has become aware of the positions of all the PUCs.

So my attitude on this is very simple. Let us stay out of prejudicing this decision. Let FERC do its job to determine whether this project is in the public interest, and not make ourselves vulnerable—and frankly the Commission—in further legal proceedings in what I think is a blatant attempt to intimidate FERC and delay this action.

So Mr. Chairman, I regret to have to be as blunt as that, but that is how I look at this hearing and these proceedings, and I hope that we will not regret this action.

The CHAIRMAN. Senator Bradley, this is not an attempt to intimidate FERC. To the contrary, I made clear in my opening statement that if there is any question to the chairman that he feels would deal with his impartiality, he should not answer it. I hope the tone is not one of intimidation.

This committee has a responsibility for a national energy policy, and if in fact what the independent producers say is correct—maybe this decision is correct, I do not know, but it is clearly something that this committee ought to deal with. We deal with legislation. We deal with oversight. We deal with national energy policy. If the playing field is tilted, we ought to find out about it. This is bigger than just one decision. It deals with whole national energy policy.

Perhaps the decision is correct, and perhaps it can be corrected in other ways. For example, we have a rate design policy statement that the FERC has said that they may apply on a case-by-case basis. We ought to delve into that and see what they are going to do.

Simply because there happens to be one pipeline application pending does not relieve this committee of its oversight responsibility or of its legislative responsibility. I hope we are walking the line correctly between discharging our responsibilities of oversight and legislation and not getting into the quagmire of the *Pillsbury* decision. Perhaps you think we are not doing that. That is what we are trying to do, but I can tell you it is a very, very important issue as far as domestic producers are concerned.

I do not know how or where the rest of the country is as to what has happened to domestic producers, both oil and gas, in the

United States. They are an endangered species. If they are an endangered species, then the country is endangered because domestic production is dropping off and rig count is not coming back.

Secretary Schlesinger testified here the other day that by 1995 we may be importing two-thirds of our energy, that the import bill may be as big by 1995 for imported energy as it is for all the rest of the mercantile trade balance. I think that is a serious matter which this committee must look into. If it deals with something that is sensitive to FERC, I do not want to get over into that business with them, but we have a responsibility, too.

Senator BRADLEY. Mr. Chairman, this has gone on for years, and on the eve of a decision to have a hearing on this issue I think puts you right in the Pillsbury quagmire.

Now the testimony of FERC and DOE I hope will be short, concise and without a lot of questions. It is the testimony from the last panel that I think we are awaiting to hear.

Mr. Chairman, I am not going to get into arguing the merits of the *Iroquois* case here at this time. I might later.

The CHAIRMAN. Senator Domenici.

Senator DOMENICI. Mr. Chairman, I have no opening remarks. I thank you for calling the hearing. I believe it will be helpful to the Commission and to everyone. I frankly believe the Chairman and the Commission probably have as tough a job as any commission in the United States. Perhaps the only one that has more technical things to consider may be the NRC.

I am here because I am concerned. I am not trying to influence any decision, nor do I come here to make the job of this Chairman and the Commission more difficult. My interest is that the application of rules to the importation of natural gas be done in a manner which is fair to the American producers and that we have rules that are fair. We all know Canada prices natural gas commodity versus fixed prices different than is normal in the United States, and that is a very, very difficult issue for the Commission and difficult for our producers, in that in some states the commodity price governs not the overall price.

In Canada they do things differently than we do. We now have a Canadian Free Trade Agreement, and it enters the discussion. What impact does it have on our authority in the United States and theirs to take into account the different way of pricing the commodity and the fixed part of the transportation? That is important, because if you do not do that right you do not have a fair playing field for American producers and American gas. That is the kind of thing that I would like to find out, Senator.

I hope it is not intended to do what you are worried about, Senator Bradley. I do not think it is. I appreciate your genuine interest and your state's concern. You must know that there are states that produce gas that have a great concern that this all be done fairly and that there be a fair playing field. Beyond that, we leave it in their hands.

Senator BRADLEY. Mr. Chairman, may I answer?

The CHAIRMAN. Yes.

Senator BRADLEY. The fact of the matter is the Northeast needs gas. The Northeast could not get enough gas from domestic producers. It went to the Canadian market to get the gas. Last December in the State of New Jersey we had curtailments because we could not get enough gas. Well, we will just tax coal more, I guess.

So I would just say that you cannot possibly expect a region of the country after countless hours have been invested and when you have experienced a curtailment in December not to care and have great concern about a hearing that clearly has the intent of saying delay.

Of course, we know why certain people want a delay. They want a delay beyond the point where the Canadian contracts expire, period. That is what is happening here. That is what this is all about. Everybody in the room knows that.

So I would only say that these are actions that were taken by northeastern states because they need gas and because they entered into contracts. They are the buyers. They are the ones to determine whether the contracts are in their interest. I would hope that this hearing will proceed quickly and that we will move on and let FERC make its decision quickly.

The CHAIRMAN. Senator Ford?

Senator FORD. Mr. Chairman, it is interesting to listen to my colleagues. One of the fruits of the controversy is reliance by electric utilities on natural gas. I struck a note back there in the back. [Laughter.]

Senator FORD. This is an argument between the big gas States and the Northeast. Mr. Chairman, I am very pleased to be a spectator in this discussion. [Laughter.]

The CHAIRMAN. Senator Burns?

Senator BURNS. Thank you, Mr. Chairman. I have no opening statement. I am just going to follow the honorable Senator from Kentucky around and pick up what he leaves. I, too, will be a spectator but a very interested one.

Thank you very much.

The CHAIRMAN. Chairman Allday.

STATEMENT OF HON. MARTIN L. ALLDAY, CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION, ACCOMPANIED BY WILLIAM S. SCHERMAN, GENERAL COUNSEL

Mr. ALLDAY. Thank you, Mr. Chairman and Members of the committee. Because of the importance of this particular proceeding that is going on at the Commission, I would like to read my statement at this time. I think it would be worthwhile.

The CHAIRMAN. Certainly.

Mr. ALLDAY. I am pleased to be here today to present testimony regarding the Commission's processing of applications for authorization to provide additional natural gas service to the Northeastern United States. The committee has focused today's hearing specifically on various aspects of Iroquois Gas Transmission System's application for a certificate of public convenience and necessity.

In light of that, let me make clear from the outset that since the Iroquois application is currently pending before the Commission, I cannot discuss in any way the merits of that proposal or any other pending matter in order to protect the integrity of the Commission's decisionmaking process. This will regrettably preclude me from addressing several of the issues raised in the committee's letter to me dated April 19, 1990.

I can, however, discuss generally the procedures followed by the Commission in northeast certificate proceedings and how these procedures are being applied. Again, I cannot discuss or prejudge any aspects of any pending certificate application. With this in mind, the committee asked me specifically to direct my testimony to the following:

One, the Commission's statutory duty under the Natural Gas Act to set applications for certificates of public convenience and necessity for hearing before an administrative law judge;

Two, how the Commission intends to fulfill this statutory obligation in acting on intervenors' motions that the Iroquois certificate application be set for an evidentiary hearing;

Three, the role which expert testimony, cross-examination and briefing plays in the Commission's consideration of the various public interest issues, including market need, facilities sizing, the viability of alternatives, environmental issues and rates underlying a Commission determination that a pipeline proposal is in fact in the public convenience and necessity;

Four, whether the Commission intends to act consistently with the pledge made by former Chairman Hesse in response to an inquiry made by Senators Bradley and Dodd that all parties would be allowed ample opportunity to express their cases on the merits of the Iroquois certificate application; and

Five, the manner in which the Commission's "as billed" decision in Opinion Number 256 applies in the context of the Iroquois certificate application and Iroquois' proposed initial rates.

Before I respond to your specific questions to the extent that I can under the constraints above, I would like to give you a brief history of the Iroquois application which is before the Commission.

In May 1986, Iroquois filed an application under Docket No. CP86-523-000 and the Commission's optional certificate procedures requesting authorization to construct and operate a 358-mile pipeline system from the Canadian border through Connecticut and New York to a terminus on Long Island in New York.

Iroquois proposed to provide 352 million cubic feet per day of firm and interruptible transportation service on an open access basis through its proposed line to various shippers in the Northeast.

Iroquois' optional certificate application which under the Commission's regulations would have received less rigorous scrutiny on the issues of supply and market need than the traditional section 7(c) certificate application evoked strong opposition. In fact, the provision of the fiscal year 1988 continuing resolution, P.L. 100-202, prohibited the Commission from expending any funds for the purpose of issuing an optional certificate to Iroquois until such time as the environmental analysis of the project was complete.

On July 24, 1987 the Commission issued a notice initiating an open season for the filing of proposals to provide new natural gas service to the Northeast. The open season was designed to notify any potential applicant seeking to bring gas to the Northeast that applications for new service and construction had to be filed by

January 15, 1988 in order to be considered in a comparative proceeding.

In response to that notice, Iroquois filed an alternative proposal under the Commission's traditional Section 7(c) procedures, which would follow the same route and provide essentially the same services as its earlier optional certificate proposal.

Seventy-one other applications were filed by the Commission's open season deadline. These 72 separate applications were consolidated into 31 distinct projects. After a series of settlement discussions held in the spring and summer of 1988 to determine which, if any, of the projects would be processed discreetly from the others—in other words, without the need for comparative hearings, the Commission consolidated 13 projects, which were still deemed at that time to be potentially competitive, into a single proceeding, and ordered the appointment of a settlement judge.

As a result of this process, settlements were reached among the parties, reducing the 37 applications involved in the 13 projects referred to the judge, to 10—or about 10 discrete projects. An amended Iroquois 7(c) proposal, together with an application by Tennessee Gas to provide certain downstream transportation services, is one of those 10 discrete projects.

Pursuant to the amended application filed by Iroquois on December 29, 1989, Iroquois is proposing to construct and operate approximately 370 miles of new pipeline at an estimated cost of $582.6 million, and to provide firm transportation for 575.9 MMcf per day of Canadian natural gas to 17 local distribution companies and three cogenerators in New York, New Jersey, Connecticut, Massachusetts, Rhode Island and New Hampshire.

I would like to outline briefly the numerous opportunities the parties in this proceeding have had to submit their views on all public interest issues. The evidentiary record in this proceeding is voluminous. For instance, over 150 parties have requested intervenor status. Over 1,000 comments, protests and answers have been filed. A great many of these filings address environmental issues, while others address the need for the proposed service, alternatives to the proposed project, rights, and other relevant issues.

Let me show you, Mr. Chairman, just how voluminous the docket sheets alone are in the Iroquois Section 7 proceedings. That is this stack of things here. Each page has got a number of entries on it. Each entry represents one to 100 pages, and maybe more than that, of pleadings. That is what is confronting us in this particular case. These hundreds of pages simply list the pleadings, ranging from one to several hundred pages, as I indicated, filed in this case.

The Commission staff issued a draft environmental impact statement in conjunction with the Iroquois Tennessee project on November 14th, 1989. The deadline for filing comments on that draft EIS was February 16th, 1990. A large number of comments were filed both before and after the deadline. All timely filed comments, and to the extent possible, late filed comments, as well, will be addressed in the final environmental impact statement, which should be issued early this summer.

Six public scoping meetings have been held in connection with the Iroquois application. The first was held in Danbury, Connecticut, in October of 1987. Two more were held in Albany, New York, and Danbury, Connecticut, in March of 1989. In January of 1990, public meetings were held in Danbury, Albany, and in Amherst, Massachusetts.

Hundreds of interested citizens attended these public meetings and took the opportunity to express their views regarding the project to the Commission staff members in attendance at those meetings. The transcripts of these meetings and written comments presented at them are also part of this record.

The Commission staff has issued numerous data requests in connection with the project, soliciting information from both the project sponsor and its customers, in order to compile the record for this proceeding. In addition, on November 20, 1989, a public technical conference was held on the Iroquois proposed rates, and additional comments on the rate issues were solicited from all interested parties.

When the Commission next considers, I repeat, next considers the Iroquois proposal, all of this information will be thoroughly analyzed by the Commission in order to determine whether the case can be appropriately resolved on the basis of the written record, or whether further proceedings are needed.

The Commission is dedicated to protecting the due process rights of all participants in our proceedings. Indeed, one of the underlying motives of using an open season process was to be fair to all potential applicants and parties. I would emphasize that at this point, the Commission has not made a determination concerning whether further proceedings are necessary to process the application.

Ultimately, that determination must be made in light of what the law requires of the Commission, and what further proceedings the Commission must hold to ensure development of a complete record in this case. That is what lies ahead for the Commission to resolve.

Turning now to your specific questions. Again, keeping in mind what I can say in line with what I said earlier. Section 7(c)(1)(b) of the Natural Gas Act requires that the Commission set certificate applications for hearing. However, the courts have held in numerous cases, including *Mobil Oil Corporation* v. *FPC,* 483 F.2d 1238, that the term hearing, in an administrative context, does not necessarily mean trial-type proceedings, or even oral presentations.

Indeed, in *Amador Stage Lines, Inc.* v. *U.S.,* 685 F.2d 333, the court held that an administrative agency has the discretion to deny an oral trial-type hearing with cross examination, even where material facts are disputed, as long as the disputes can be adequately resolved through written submissions.

In my judgment, what the courts require is that the procedures used adequately test the Commission's factual determinations and create a record that will allow a reviewing court to examine the reasonableness of the agency's action. The Administrative Procedure Act provides for such cross examination as may be required for a full and true disclosure of the facts.

For example, cross examination may be valuable in instances where a witness's motive or his intent or his credibility needs to be considered in addition to documentary evidence. However, the witness' demeanor is often of limited value to the trier of fact in the kind of cases which we have before the Commission.

For instance, in *American Public Gas Association* v. *FPC*, 498 F.2d 718, the D.C. Circuit upheld that Commission's decision not to hold an oral hearing or allow cross examination, where the parties requesting such procedures had failed to point to any specific weaknesses in the written evidence which might have been explored or developed more fully in an oral, rather than a written context.

The Ninth Circuit, in *Sierra Association for Environment* v. *FERC*, 744 F.2d 661, ruled that the Commission acted within its discretion in adopting a paper hearing procedure, because the petitioner had failed to point out the existence of any specific disputed facts that should appropriately be resolved through a trial-type proceeding, or to indicate how it was prejudiced by the paper hearing process.

Thus, as a matter of law, mere allegations of disputed facts are insufficient to warrant setting a trial-type hearing. A petitioner must make an adequate offer of evidence to support such allegations. The Commission may, in its discretion, deny an oral hearing, even where material facts are disputed, so long as the disputes may be adequately resolved on the basis of the written record.

Thus, it is important to realize that in appropriate circumstances we can and do give interested parties their full day in court without a formal trial-type hearing.

As you noted, Chairman Hesse pledged that "The merits of all the public interest issues, including the firmness of supply and demand, the viability of alternatives, and environment and rates will be fully addressed during the proceeding of each certificate application. During these proceedings, each party will have an ample opportunity to participate in the formulation and resolution of issues, and to present its case."

I stand behind and reconfirm that pledge. In doing so, however, I would note that Chairman Hesse did not, nor could she have, promised the precise nature of the proceedings to address the issues in any particular case. As stated previously, no inference from what I have said should be drawn from the foregoing on what the Commission may do in this case and in the future.

Finally, you have requested that I address the manner in which the Commission's "as-billed" decision in Opinion No. 256 applies to Iroquois's pending application for a certificate of public convenience and necessity. Opinion No. 256, issued by the Commission in 1986, addressed the appropriate way for an importing interstate pipeline to recover from its sales customers the costs incurred by the pipeline for Canadian gas purchased to serve those customers.

In brief, Opinion No. 256 states that a pipeline should recover its Canadian gas costs in the same way that it recovers its U.S. gas costs, regardless of how the Canadian exporter may bill these costs; and in that instance, costs were billed under a two-part rate, which put all fixed costs, gas and transmission related, into a demand charge.

To implement its policy decision, the Commission considered two major types of costs reflected in the Canadian gas charged: fixed gas costs and fixed transmission costs. The Commission ordered that the fixed gas costs, or production related costs, be recovered through the commodity component of the importer pipeline's sales rate, just as a U.S. pipeline recovers such costs when they buy gas from U.S. producers.

The Commission ordered that fixed transmission costs, that is, the Canadian pipeline costs imbedded in the Canadian gas sales charges, be recovered in a manner consistent with the way that the importer pipeline recovered its own transmission costs. That is, through a modified fixed variable rate, with some of the fixed transmission costs being recovered through the commodity component, rather than recovering all the fixed transmission costs in the demand component, as the charges were billed by the exporter.

Opinion No. 256 dealt only with sales for resale rates. In the case addressed by Opinion No. 256, the pipeline proposed to purchase and take title to the Canadian gas at the border, then sell it for resale in the United States. The Iroquois application involves transportation only, and no sales for resale are being proposed. Thus, no gas costs are pending before the Commission in the Iroquois proceeding. Therefore, the provisions of Opinion No. 256 do not apply explicitly to the Iroquois application.

As noted in the committee's April 19, 1990 letter, Opinion No. 256 was not overturned and is consistent with the principles of the United States/Canada Free Trade Agreement. The basic thrust of the FTA is to eliminate to the maximum extent possible governmental barriers to free trade between the U.S. and Canada. In general, the agreement directs each party to accord "national treatment" to the goods of the other party.

In the U.S. energy regulatory context, this means according Canadian energy supplies treatment that is no less favorable than the treatment accorded U.S. energy supplies. In essence, therefore, the FTA requires that each country's domestic energy laws and regulations should not discriminate between domestic and foreign goods on the basis of nationality. FERC must abide by this law.

Let me conclude with a personal note here for a moment, Mr. Chairman. As you all know, I lived and practiced law in west Texas for over 30 years. During that time I was friends with and I represented many oil and gas producers. I was delighted when those hard-working folks prospered during the boom years. And I have felt their pain and their despair during the lean years.

If I can be so bold, Mr. Chairman, there are not many folks in this room today who have more firsthand knowledge of the way the ever-changing nature of the oil and gas business affects the Nation as a whole as well as the individuals and their families who help produce oil and gas supplies than I.

At the same time, Mr. Chairman, you may recall that my intention and resolve to perform my current responsibilities evenhandedly, in light of my previous background, was discussed openly during my confirmation hearing for FERC Chairman. I committed to this committee then, and I commit to it again today, that I am going to do everything I can to deal fairly, openly, and impartially on all issues coming before the FERC. Whether it hurts or helps my home folks, I am going to do it straight from a level field.

I have strived during my six months on the job to keep an open mind on everything, while always keeping in mind the Commission's ultimate mandate, to protect consumers. Simply stated, while the Commission always considers the arguments advanced by all participants in the gas industry, we must ultimately reach a decision that protects the public interest.

And although I have had over 30 years experience in the oil and gas industry, I fully understand, I accept, and I will endeavor to discharge my responsibilities to ensure the Nation's consumers adequate energy supplies at just and reasonable rates.

Senator Bradley, I am not intimidated at this hearing. [Laughter.]

With respect to the domestic producers, they are my folks. That is where I came from. I do not apologize for that. Problems at this agency, Senator Domenici, I think are about as tough as any in this country. We wrestle with them daily. We are going to do the best we can, but we are going to shoot straight.

Mr. Chairman, that concludes my remarks. I appreciate the opportunity to be here as you consider this matter, and I thank you.

The CHAIRMAN. Thank you very much, Chairman Allday. Your statement refers to a series of cases, with which I certainly agree, which point out that the Commission does have the authority to grant either full evidentiary hearings or to have hearings on the basis of only the record. And that same body of law also points out that the Commission can go halfway, or a fourth of the way, that it can limit its evidentiary hearing to specific issues.

Now, considering that, would it be worthwhile for the Commission to consider a limited evidentiary hearing under an expedited procedural schedule? Could you not design such a hearing that would not impact or delay the matter, particularly considering the fact that there is, as I understand it, presently pending in Canada, before the Canadian National Energy Board, a decision on the pipeline up there?

So it seems to me that a limited evidentiary hearing, under an expedited schedule, could be granted here without delaying the project. Is that so? I mean without reference to whether it should be done, could you grant that without delaying the project?

Mr. ALLDAY. I think we could grant it; I do not know if it would delay it somewhat. Sure. I am not saying which way—the Commission certainly will consider that. That is part and parcel of what we are going to undertake, and it is the proper way for everybody to get their say.

The CHAIRMAN. I would like to make clear that I have not only not opposed the Iroquois project, I was the co-author of a bill that—what does it say? [Laughter.]

A very good bill. [Laughter.]

Mr. ALLDAY. If I run into trouble, I will be leaning on him, too, if that is all right.

The CHAIRMAN. This is S. 2667, introduced in the 100th Congress, dealing with global warming, and section 1101 of it requires the Chairman of the Federal Energy Regulatory Commission to prepare and transmit to the Congress recommendations for enacting legislation to expedite final Commission approval of new pipeline projects to serve markets in the northeast United States.

So I want to make clear, this is no delaying action on my part.

Mr. ALLDAY. Yes, sir. Well, I just indicated that sure, we could do what you ask. I could not guarantee it would not delay it.

Senator BRADLEY. What was that again?

Mr. **Allday**. I said sure we could do it, but I could not guarantee that that might not delay our decision.

The **Chairman**. Chairman Allday, you do have this rate design policy statement, and there is an indication that the rate design policy statement will be applied on an ad hoc basis to rate cases that come before the Commission.

Mr. **Allday**. Yes, sir.

The **Chairman**. Now it seems to me that if in fact the playing field is not level, that that is a rather cumbersome process and a very slow process, considering that rate designs come up about every three years, and it also would be very expensive.

Have you thought about something like an order 500, regulations that would level the playing field that would be applicable to all pipelines immediately and simultaneously? Is that possible here?

Mr. **Allday**. Senator, I think the staff, if you go over there and talk to them, will say, my gosh, Martin is beating on us, we are going to have to shorten everything while he is here. And I am put out with the delay that apparently permeates government in general, but certainly the FERC while I am there. And I have urged them to figure out ways to shorten the certification process. They are thinking about every which way that they can, yes, sir. We are thinking about it.

You know the rate design policy is one of the hardest things I had to figure out in my own mind, and I think I understand it now fairly well. But a generic-type order would be very difficult, I think.

The **Chairman**. I know it is quite difficult, and I know it is highly technical, but I am sure you recognize better than I the difficulties of applying a general policy statement on an ad hoc basis as these cases come up, and recognize how expensive it is, and how much delay there is in that situation.

Mr. **Allday**. I am going to be talking to 2,000 lawyers tonight at the FEBA banquet, and yes, I know what you are talking about, being expensive.

The **Chairman**. Now lawyers do not necessarily oppose delaying.

Mr. **Allday**. I understand. [Laughter.]

The **Chairman**. Senator Bradley.

Senator **Bradley**. Thank you very much, Mr. Chairman.

Thank you for your testimony. I take you at your word.

Mr. **Allday**. Okay. You need to, sir.

Senator **Bradley**. And I think you were very candid with us in responding to the Chairman's question that a full-blown evidentiary hearing was going to delay.

Mr. **Allday**. I did not say it would, I said it could.

Senator **Bradley**. It could, right. It could delay.

Mr. **Allday**. Yes, sir.

Senator **Bradley**. That is precisely what we are concerned about. And you know, you delay long enough and it becomes a moot issue because the contract expires. And I assume people understand this. The Northeast wants gas. If we get all the gas from domestic producers, that is terrific. We cannot. We cannot get enough through the pipelines. That is why we went to Canada.

If we do not get the Canadian gas, the result is more imported oil. So the choice is really Canadian gas or imported oil. And again, I hope you will—I know you will. I appreciate your candor and your straightforwardness here today. People in the Northeast simply want a decision, and do not want to lose out because of delay. And I know you understand that.

Mr. **ALLDAY**. Yes, sir.

The **CHAIRMAN**. Senator Domenici.

Senator **DOMENICI**. Mr. Chairman, I heard Senator Nickles say that he was on a very short time limit. You only have a few minutes?

Senator **NICKLES**. Just a couple of moments, yes.

The **CHAIRMAN**. Senator Nickles, then.

Senator **DOMENICI**. I can stay for a half hour or so, so go ahead, Senator.

Senator **NICKLES**. I will not take that long, and I appreciate it very much, Senator Domenici.

And, Chairman Allday, welcome to the committee.

And I would echo the comments, I do not think this hearing is to try to intimidate anybody. It is interesting to try and get into this issue, which is an important issue and which I have heard personally a lot of conflicting things. And so I compliment the Chairman for the hearing. I, likewise, have written you a letter asking for the full hearings.

How long would that take? Because it is not in my interest to delay the project or to tie it up indefinitely, or anything else. How long would full evidentiary hearings take?

Mr. **ALLDAY**. I would have to ask my general counsel to help me on that, if he could, but I do not think there is any way for really guesstimating how long it would take.

Senator **NICKLES**. Are we talking about months? Are we talking about years?

Mr. **ALLDAY**. Oh, I would not think years. I hope not.

Senator **NICKLES**. I hope not, too.

Mr. **ALLDAY**. It will not. Let me put it that way.

Senator **NICKLES**. Does counsel want to supplement that?

Mr. **SCHERMAN**. Senator, I think it would depend upon the scope of the hearing, the issues that the Commission set for hearing, and whether environmental issues would have to be considered, as well, in the hearing. So it is very difficult to say. We have had full-blown trial-type hearing rarely in certificate cases over the years. They have lasted for years in some instances—two or three years. Others have been shorter. It really depends on the breadth of the issues that the judge has to consider that the Commission sets.

Senator **NICKLES**. Well, I am well aware of the fact that some people would use hearings, whether it is environmental impact hearings or whether it be rate proceedings or whatever, to delay the process. And I can share the frustration of the Chairman of wanting to move, and Senator Bradley and others.

And so let me state again that I have understood that there are some questions. As a matter of fact, I just looked at IPAA's statement, and I might ask for your response to it. It is on page one and two of their statement. This is Mr. Hilliard's statement, it says the purpose of this is to bring to your attention the failure of the Department of Energy and FERC to permit IPAA and other parties to present evidence of undue discrimination caused by certain anticompetitive pipeline projects and show that cheaper domestic alternatives exist.

Has that opportunity been denied for people to show that there is discriminatory activity, or is there discriminatory activity on behalf of our friends from Canada?

Mr. ALLDAY. I am not going to answer the last question, because that is a pending situation. I will answer the first part of it. They have had an opportunity to participate by submitting material to us.

Senator NICKLES. Well, I am very interested in a "level playing field."

Mr. ALLDAY. Me, too.

Senator NICKLES. And the Free Trade Agreement, that is the purpose, and that was the comment you made in the last page or two of your statement.

Mr. ALLDAY. Yes, sir.

Senator NICKLES. But we are interested in, more or less, a level playing field. We do not want to give our Canadian neighbors an undue advantage over domestic producers, either.

Let me ask a question. Senator Bradley mentioned the fact that he did not think that it was possible that the demands from the Northeast could be met domestically on natural gas, and therefore the alternatives were either Canadian imports in natural gas or imported oil. Do you agree with that summation?

Mr. ALLDAY. I would have to be candid with you and say that there are some efforts being made, I think, and will be coming before the Commission to bring southwest gas up to this neck of the woods, if I can call it that. But I do not see it happening very soon. And it gets cold up here every once in a while, and I am sympathetic to that.

We are going to treat them fair, and look at each issue as it comes up. We do not have a pending application currently, I do not believe, to build a big pipeline to come up here. One is not on our plate.

Senator NICKLES. In the first part of your statement you mentioned originally 70-some applications, and then it was narrowed down to 30. Did all those applications go by the wayside?

Mr. ALLDAY. No, a lot of them have been considered.

Senator NICKLES. Discarded or what?

Mr. ALLDAY. Seventy-two applications were the subject of the open season. Thirty-one of those projects resulted after a consolidation of those. Thirteen projects were then consolidated and sent to Judge Wagner as a settlement judge. And the remainder of the 31 were processed as discrete items.

Two projects were severed for discrete processing by Judge Wagner. Four projects were certified with the Commission in a final settlement: ANR, that is a domestic deal, Iroquois, Champlain, and NIPS III.

The scorecard is 27 total projects, 19 certificates heretofore issued, eight projects pending, and these include the six projects listed above, and a couple of others.

Senator NICKLES. But are those projects competing pipelines that would bring additional supplies to the Northeast?

Mr. **SCHERMAN**. Senator, by virtue of the fact that the Commission has issued a certificate for those applications, the Commission has previously made a finding that they were discrete projects and were not competitive for purposes of a comparative hearing. Many of those 18 projects do involve bringing domestic gas to that region of the country. So there is a number of projects that the Commission has already certificated that involve domestic supplies.

Senator **NICKLES**. Well, I am not sure I have the answer I am looking for. You mentioned ANR, which was the only one that I recognized out of that last four, but we have a lot of gas in our state that we are not selling. We have a lot of gas that is still shut in. We have a lot of gas that is priced at very low prices.

Senator Bradley mentioned importing, and we have gas that is selling for $1.40. So to state the equivalent on a per-barrel basis, you are looking at $7.8 oil. So gas is still relatively very cheap. That is before transmission charges, but still very cheap in comparison to other fuel supplies. We would like to help move some of that gas to the northeast. At least we would like for it to have the opportunity to be competitive with the Canadian gas. And hopefully it would be evaluated in a fair manner.

I am concerned about the Canadian gas and how it would be charged, what kind of rates are going to be assessed, both in commodity and in transmission, and how that compares to natural gas in the United States. That is really all I am looking for. Again, I am not trying to oppose this project in any way, shape or form. I am just wanting to make sure that domestic producers have a fair shot and that we are not discriminated against in comparison to the prices through this Iroquois project.

Mr. **ALLDAY**. That is just what we got through doing in the NIPS II case, leveling the field as best we can—leveling the field, with respect to transmission of the Canadian gas that is to come across at that point. We did that two weeks ago.

Senator **NICKLES**. Well, I am not familiar with the NIPS II case.

Mr. **ALLDAY**. The sale of the gas is not jurisdictional. That is up in Canada. And we cannot, if I can put it this way, mess around with that.

Now let me say something, Senator.

Senator **NICKLES**. Sure.

Mr. **ALLDAY**. And maybe I should not, but I am going to. I hope I am not saying something I should not. But I wish that some of the Midland County gas was going up there. I am telling you that I recognize what you are saying. But I have got to follow what I perceive to be the law, and we intend to.

Senator **NICKLES**. Are the pipes to capacity, or are they beyond capacity right now?

Mr. **ALLDAY**. You know, we take each application as it comes to us on a day-to-day basis, and if one comes down the pipeline they have my vote, I think, depending on what the facts show.

Senator **NICKLES**. I am interested in an answer to that question, though. Are the existing pipelines all right now at capacity or exceeding capacity? I am familiar with the pipelines that run to the northeast. You have Transco, Texas Gas——

Mr. **ALLDAY**. My OPPR folks tell me yes.

Senator **NICKLES**. All those are pretty much at capacity?

Mr. **Allday**. Yes, sir, at peak periods.

Senator **Nickles**. Have they filed an application to increase capacity?

Mr. **Allday**. Yes. A couple of them have.

Senator **Nickles**. Have those been granted?

Mr. **Allday**. Not yet. They are pending.

Senator **Nickles**. Are those being stuck in the paperwork process that again will make it more difficult for your producers in Midland, et cetera, to get the gas to the market? That is my question. I want that gas to have a fair chance.

Mr. **Allday**. It will have a fair chance.

Senator **Nickles**. I appreciate that.

Mr. Chairman, thank you.

One final question. Does the U.S.-Canadian Free Trade Agreement prevent FERC and DOE from executing its duties and responsibilities under the Natural Gas Act and the Natural Gas Policy Act to make sure that the Iroquois project is not discriminatory and is a public convenience and necessity?

Mr. **Allday**. I am sorry. I hate to make you repeat that long question.

Senator **Nickles**. Does the U.S.-Canadian Free Trade Agreement prevent FERC and DOE from executing its duties and responsibilities under the Natural Gas Act and Natural Gas Policy Act to make sure that the Iroquois is not discriminatory and is a public convenience and necessity?

Mr. **Allday**. No.

Mr. **Schroeder**. Senator, speaking for the Department of Energy, the answer is no.

Senator **Nickles**. Thank you very much.

Thank you, Mr. Chairman.

The **Chairman**. Senator Domenici.

Senator **Domenici**. Mr. Chairman and Senator Bradley, let me just try to put into perspective my concern. First, I have been a staunch advocate of getting as much natural gas to middle America and Northeast America as anyone around here. I was here preaching deregulation before you were here when we were going to have a real curtailment in Ohio because regulation had caused such a strange market. As you might recall, that while there was plenty of gas around in reserves, we could not get it delivered anywhere, much less to the Northeast. So I live for the day that natural gas which we have in abundance out there in our country is deliverable to places in the United States where we cannot now deliver it.

You should know from my state's standpoint we are a very large producer of natural gas, and we have a most difficult problem in that we cannot get our natural gas delivered. It is locked in. We do not have the right transportation system. You have been an advocate of changing the transportation system, which surely has gone through a great change, so that it becomes competitive and so that we can move gas through it that is indeed the cheapest gas.

I am concerned about the consumer getting the cheapest gas. I believe you are. Frankly, one of the things that concerns me about this particular pending application and the building of a major transportation system, which I think should concern you, is that indeed it may provide natural gas to people you are concerned about, but it also may end up providing them with natural gas that is not the cheapest natural gas. That is what concerns me.

I do not know how to do that, but I do not want this case to be precedent for giving preference to Canadian gas at the price level, not the transportation level. Remember, we are trying to distinguish between the two, the price of the product. I am concerned that it may be precedent that will indeed further prejudice our domestic natural gas versus some Canadian natural gas because we will not be applying the rule of the price of the commodity but, rather, we will be entangled with trying to fill a pipeline.

I remind the Senators here, for the record California is in a very strange position because the utilities have built very large transportation facilities. Now they have to pay for it, and the utility commissions are requiring that they keep them full. That does not mean that the price of the gas going into the pipelines is always the most competitive gas or that those who want to supply it get a fair shot at trying to supply it.

I did not come here to interfere with the pipeline and with your proceedings, but I do not want the wrong precedent to be set in terms of the future, and I want to make sure that the consumers are getting the best deal. I do not have a solution to giving them a better deal right now because they are not getting enough gas, so something that will give them some appears to be a better deal.

I do not want it to ultimately make them captive or your policies to make Canadian gas preferential always in the future because of a pipeline, Mr. Chairman.

Mr. ALLDAY. We are going to look at each one separately.

Senator DOMENICI. All right.

Now let me talk a little bit about the Canadian Free Trade Agreement. I am not at all sure that we do not have a very serious predicament ultimately with reference to the Canadian Free Trade Agreement and the current interpretation. Now forgive me. You have answered very forthrightly with a one-word answer to Senator Nickles, but I want to just read a little bit of the history as it is in the report on the Canadian Free Trade Agreement, and then you can answer again.

Some would assert that the Free Trade Agreement binds the hands of DOE and FERC and prevents you from examining the terms and conditions under which gas is being imported, including related transactions in Canada, and from taking into account as may be appropriate to address or mitigate anticompetitive or discriminatory provisions of the import authorization or subsequent rate design.

Before I ask you the question, let me read a bit out of this record. It is very, very brief. That is page 61 of the report on the Canadian Free Trade Agreement. "Sections 4 and 5 of the Natural Gas Act require that charges for interstate transportation of natural gas be just and reasonable"—those words are in quote—and not "unduly discriminatory or preferential."

One more paragraph, "The agreement does not in any way affect the ability of the U.S. regulatory authorities, including ERA or FERC, to impose appropriate terms and conditions on import and export of natural gas under the Natural Gas Act. The committee sought and received assurance that nothing in the agreement alters, supplants or preempts the mandate of the Natural Gas Act." That is a direct quote.

With respect to the impact of the Free Trade Agreement on FERC's Opinion Number 256, the so-called "as billed", the decision says that gas imported from Canada must receive the same rate treatment as domestic gas. The report goes on at length to make clear that the agreement does not affect that principle. Quoting the Canadian ambassador, "The Canadian government does not view FERC's 'as billed' decision as being inconsistent with or affected by the Free Trade Agreement."

Would you not agree that the Free Trade Agreement does not prevent the Department of Energy and the Federal Energy Regulatory Commission from reviewing the terms and conditions on imports of natural gas and from imposing such terms or conditions which are necessary to offset or mitigate elements which are discriminatory or anticompetitive?

Mr. ALLDAY. Senator, I do not believe the Commission has jurisdiction to address itself to the sale of gas in Canada. I do not know if that answers your question, but to me it does.

Senator DOMENICI. So you are saying?

Mr. ALLDAY. I think you have a problem with the Free Trade Act. If you want to change that around, that is your prerogative, not mine.

Senator DOMENICI. I understand that that is your interpretation, and maybe that is correct; but once it comes into the United States——

Mr. ALLDAY. We can deal with the transportation, and that is exactly what we did in the NIPS II case. We leveled the field.

Senator DOMENICI. You can deal with some of the events that have occurred in Canada that you might want to take into account to level the playing field.

Mr. ALLDAY. Not with respect to the sales. We can with respect to the transportation. That is exactly what we did.

Senator DOMENICI. All right.

Senator BRADLEY. The Senator might want to yield on that question.

Senator DOMENICI. What if you have a discriminatory sale in Canada? What can you do about it?

Mr. ALLDAY. That is the Department of Energy, I guess, on the importation question. I do not know how they would look at that. You will probably have to ask them.

Senator DOMENICI. What do you think about that?

The CHAIRMAN. May we go ahead and finish with Chairman Allday and then have Mr. Schroeder.

Senator DOMENICI. I am sorry. I just thought that DOE was going to answer the question. I have to ask him later?

The CHAIRMAN. Yes.

Senator DOMENICI. What happens if there is a discriminatory sale in Canada? You are saying you have no jurisdiction?

Mr. ALLDAY. It seems to me that is an importation question as opposed to what we are supposed to be dealing with, Senator.

Senator BRADLEY. Senator, would you yield?

Senator DOMENICI. Sure.

Senator **Bradley**. Under the Act, under the Free Trade Agreement there is essentially a kind of dispute settlement mechanism that is set up if there are disagreements as to what is or is not a violation. That was the subject of endless discussion during the free trade negotiations and also during the bill itself.

The other issue is really the price for domestic producers. What would the price be for domestic producers if you had to build another pipeline to get the gas to the Northeast? That is an issue.

Another issue is what about a 15-year contract? This is a 15-year contract. There will be people before the committee shortly, and I want to explore that.

So there are a lot of moving parts here, and, believe me, my interest is simply to assure that the Northeast gets access to gas. As to some hypothetical possibility 12, 13, 14 years down the road that a pipeline might be built and more gas be coming from the southwest, if it was there today, believe me——

Mr. **Allday**. Senator Bradley, let me add something here. Maybe I should not, but I am going to. I have seen that industry crumbling around my very shoulders when I was back home. We doggone well better start paying attention to the domestic industry in every way that we can. I offer that. Should I advise a Senator? I do not know, but that is what I am doing.

Senator **Bradley**. I take your point. I think you come from a very deep background, are respected, and I know that you spoke from your heart when you made your comments about the domestic industry. I appreciate that.

Mr. **Allday**. Yes, sir.

Senator **Bradley**. At the same time, in your new capacity you have to be sensitive to the fact that there were curtailments in my state in December.

Mr. **Allday**. There were curtailments in Houston, Texas and blackouts.

Senator **Bradley**. Because you could not get access.

Mr. **Allday**. Well, no. We could not get the gas. [Laughter.]

I say "we". They could not.

Senator **Bradley**. They could not.

Mr. **Allday**. They were frozen up.

Senator **Bradley**. Yes. That is a little different problem.

Mr. **Allday**. Right.

Senator **Bradley**. The problem here is you could not get the gas.

Mr. **Allday**. Both places.

Senator **Bradley**. That is what we are attempting to deal with.

Mr. **Allday**. I understand.

Senator **Bradley**. I appreciate your point, but——

Mr. **Allday**. I understand probably better than most.

The **Chairman**. Just as a parting comment, Chairman Allday, I have some other questions, but I do not want to tread on decisionmaking.

I am glad you have gotten the spirit of this committee, if my colleague from New Jersey has not, which is that we are not trying to intimidate anybody but we do want a level playing field. I do not know the ways to do it. There are allegations that there is at least an apparent price advantage for Canadian natural gas. Perhaps it is a requirement of the law because of the sale taking place beyond the border.

In any event, we ought as a country with all of our component parts, FERC, DOE, this committee and otherwise, to do what we can to insure that we have a level playing field. That was the spirit of Order 256, if not its exact terms as applied to any particular case, and we ought to find a way as a country to be fair in the spirit of Order 256. I am not saying that we are or are not. We will have some producers here who will talk about the apparent advantages.

Mr. ALLDAY. Yes, sir, but I am tired of losing lawsuits.

The CHAIRMAN. I understand that, too. We just want to work with you, and we appreciate the delicacy of this whole issue. I think you have dealt with it very well. I have nothing but admiration for the job you are doing and, I might add, for your good staff as well. It is a very difficult job.

Mr. ALLDAY. Thank you.

The CHAIRMAN. You have a very tough job. We are not trying to reverse any decision or delay any decision.

Mr. ALLDAY. I know that.

The CHAIRMAN. We just wanted to see that that playing field is level. We appreciate very much your coming, Chairman Allday. You have done a very good job.

Mr. ALLDAY. Thank you.

The CHAIRMAN. Thank you.

Next we will hear from Mark Schroeder who is Deputy General Counsel of Environment, Conservation and Legislation of the Department of Energy.

STATEMENT OF MARK C. SCHROEDER, DEPUTY GENERAL COUNSEL, ENVIRONMENT, CONSERVATION AND LEGISLATION, DEPARTMENT OF ENERGY

Mr. SCHROEDER. Mr. Chairman and members of the committee, my name is Mark Schroeder. I am the Department's Deputy General Counsel for Environment, Conservation and Legislation. In my portfolio of legal responsibilities is the natural gas import and export program. I welcome the opportunity to testify before the committee and to discuss the Department of Energy's regulation of the importation of natural gas into the United States.

The Department's policy objective in the area of natural gas is to ensure that a secure supply of gas is available to the American consumer at competitive prices. To that end, the Department believes the market, not the Government, should determine the price and other contract terms for natural gas. We pursue this policy because experience indicates that the operation of market forces, and not Government intervention results in the public receiving the greatest amount of gas at the lowest possible price.

Since 1984, the Department's policy with respect to the regulation of natural gas imports has mirrored this reliance on market forces. Our review of a proposed import is limited to a determination of whether the arrangement, taken in its entirety, is and will remain competitive over the life of the authorization. Need and supply security, although considered, are presumed to exist if an import is competitive and negotiated with a historically reliable supplier. This policy presumes commercial parties, if allowed to structure their trade arrangements free from unnecessary governmental interference, will develop flexible arrangements responsive to market forces over the life of the import. In addition, with respect to natural gas imported from Canada, in particular, our Government is bound by the terms of the Free Trade Agreement negotiated by the Executive and approved by the Congress in 1988. Under this agreement, the United States and Canada have mutually pledged equal access to each other's markets.

Your April 19, 1990 letter to Secretary Watkins invites the Department to testify regarding certain matters arising in connection with a pending natural gas import proceeding. The proceeding involves the joint applications of Brooklyn Union Gas Company and others, a group of 18 local distribution companies, for authority to import Canadian gas into the U.S. Northeast. The Department's docket number for this case is 86-44-NG, *et al.* You have requested an explanation of the rationale supporting our Conditional Order Number 368 issued on January 11, 1990, to Brooklyn Union. In addition, you have asked the Department to address subsequent agency responses to applications for rehearing of Conditional Order Number 368.

I would like to address your second inquiry first. The Department's procedural response to the two applications for rehearing of Conditional Order 368 do not reject these applications for rehearing. They were simply found to have been submitted prematurely.

The nonfinality of the conditional order in the Brooklyn Union matter arises from the Department's obligations under the National Environmental Policy Act of 1969 (NEPA) which requires Federal agencies to give appropriate consideration to the environmental effect of their proposed actions. Consistent with this mandate, approval of the Brooklyn Union import applications is conditioned on completion of the necessary environmental review and the entry of a final opinion and order by DOE. The Federal Energy Regulatory Commission which must certificate the construction and operation of the related Iroquois pipeline facilities, has the lead in preparing an EIS for the Iroquois project. DOE is a cooperating agency in this process, and only after FERC has completed the EIS and DOE has fulfilled its independent responsibilities under NEPA will DOE then enter a final opinion and order.

No natural gas may be imported under Conditional Order Number 368. Conditional Order 368 explicitly states that its findings are preliminary. DOE will reexamine the preliminary findings made in that order after completion of its environmental review and prior to reaching any final decision. Accordingly, rehearing of that order is premature. For that reason, the applications for rehearing were returned without any prejudice to their legal positions. All parties will have an opportunity to request rehearing after a final determination on the Brooklyn Union applications is made by the Department of Energy.

Your primary inquiry concerns the merits of issues raised in the Brooklyn Union proceeding. These matters will not be resolved until the DOE issues a final decision based upon the complete record of the case. Accordingly, we cannot discuss the merits of this or any case pending final agency adjudication. The Department believes, however, it is important to consult with the Congress on matters of overall policy, so I next want to discuss our import policy without discussing the *Brooklyn Union* case.

The Department is aware of the claims of domestic producers. We have given careful consideration to their concerns on several occasions. We have found, however, their past claims that Canadian gas was somehow gaining preferential access to U.S. markets over domestic gas to be unsupported. Absent support for their claims, it is the Department's policy, now manifested in the U.S.-Canada Free Trade Agreement and consistent with other regulatory initiatives on both sides of the international border, to require authorization of import arrangements in furtherance of the objective of achieving a fully competitive North American gas market.

The intended market of the proposed import is the Northeast which, as the Committee knows, is located at the end of the domestic pipeline system and is heavily dependent on imported oil to meet its energy needs. It is, therefore, a particularly attractive market for the introduction of new long-term, reliable supplies of natural gas at competitive market responsive prices. Both U.S. and Canadian natural gas producers are free to compete for this market, as are suppliers of competing fuels. The Department does not direct energy purchasers to particular suppliers. We review applications filed with us. The applications we have approved in the past have provided substantial benefits to U.S. natural gas consumers.

I would like to thank the Committee again for inviting the Department's testimony today. I will be happy to respond, to the best of my ability and consistent with the limitations previously discussed, to questions regarding the Department's natural gas import policy.

The Chairman. Thank you very much, Mr. Schroeder.

Mr. Allday, we want to invite you to stay if you would like, but you will not be needed any longer for questions. So you are certainly free to go if you wish.

Mr. Allday. If I am not subjected to any more questions, I will stay. [Laughter.]

The Chairman. That is fine.

Senator Domenici. That is risky.

The Chairman. That is fine.

Mr. Allday. I have got to have your assurance. [Laughter.]

The Chairman. Sure.

Mr. Schroeder, under Section 3 of the Gas Act, as you point out, DOE has the ability to turn down an import application based on the public interest. It would appear that DOE's procedure for reviewing applications to import Canadian natural gas has become somewhat of a rubber stamp. Has DOE ever denied an application to import Canadian natural gas?

Mr. Schroeder. That goes back over six years. I am going to have to ask someone. Yes, I am told that we have turned down applications in the past.

The Chairman. Do you know when?

Mr. Schroeder. I can get that information for you.

The Chairman. Good, I would appreciate it if you would.

[The information referred to follows:]

Prior to issuance of the 1984 policy guidelines, DOE denied applications filed by Montana Power Company, Columbia Gas Transmission Company, and Northern Natural Gas Company for long-term authority to import new volumes of Canadian natural gas (1 ERA Para. 70,502, rehearing denied, 1 ERA Para. 70,507). In all three cases, addressed in a consolidated order issued in 1980, the applications were denied because DOE found the price was not competitive with residual fuel oil and largely on this basis concluded there had not been a showing of compelling immediate need for the supplies.

Two years earlier, DOE denied, on the basis of need and security of supply, applications to import LNG from Algeria, including *Tenneco Atlantic Pipeline Company, Tennessee Gas Pipeline Company,* 1 ERA Para. 70,103.

Since the 1984 market-based policy has been in effect, DOE has not denied a gas import application. As anticipated, applicants have followed the "road map" provided by the policy guidelines. Where they have not or where there has been some question, DOE has requested additional information (for example, an interlocutory procedural order requested supplemental information on both supply security and need in *Granite State Gas Transmission Inc.*, 1 ERA Para. 70,717). Applicants have responded to correct any deficiencies and/or to supply additional information, or they have withdrawn their application (for example, in *Kern River Gas Supply Corporation,* Docket No. 86-12-NG, the applicant withdrew after DOE issued an order proposing to deny the application for long-term import authority because it was not supported by contracts). Other items, DOE has imposed substantive conditions (for example, in *Pan National Gas Sales Inc.*, 1 ERA Para. 70,133, DOE conditioned Pan National's 20-year authorization to import Algerian LNG to require separate application for domestic sales over two years; DOE also shortened the reporting period proposed by Pan National).

The CHAIRMAN. There may be some that have been turned down, but it just seems to me that that is a process that has become somewhat of a rubber stamp, and I hope it is not.

Mr. SCHROEDER. Well, Mr. Chairman, I think that there is at least an explanation for the recent experience, and that is in 1984 we issued a policy statement on what we would authorize in a natural gas import. Having provided that sort of a road map, it is reasonable to expect that the applications to import gas would tend to follow that road map. And so historically, or at least since 1984, we have been getting applications, the majority of which meet the criteria set forth in that policy statement.

The CHAIRMAN. In the 1984 import policy guidelines, it states as follows: "If the imported gas is competitive in the proposed market area, and through its contract terms will remain competitive throughout the contract period, then the rebuttable presumption exists that the gas is needed in that market."

What kind of a showing must be made to rebut that presumption?

Mr. SCHROEDER. I think the need presumption really is subsumed in the competition and the competitiveness of the gas inquiry. And as long as there is flexibility in the contract terms, particularly with respect to price, but also volume—it is a dynamic that involves the price and the volume—but to the extent there is flexibility and we are assured that the gas will remain competitive in that market, we assume that the buyers will take it when it is needed. And if they do not need it, they will not take it.

The CHAIRMAN. When DOE issues an order authorizing natural gas imports, what legal effect does that have on the ability of PUCs to regulate local distribution companies in the recovery of the cost of the imported gas?

Mr. SCHROEDER. I think that the state PUCs have retained the authority to regulate the recovery of costs by their local distribution companies for actions in purchasing gas that are either prudent or imprudent. They regulate the recovery of that and make those determinations. I do not think that the Department precludes that sort of inquiry in authorizing an import.

The CHAIRMAN. In your testimony you indicated that DOE had found that the domestic producers' past claims regarding the impact of Canadian imports were unsupported. Would you please expand on this? What were the claims of the producers and what were the Department's findings?

Mr. SCHROEDER. I can generally speak to those claims. Many of them were that the price terms were not competitive or that the gas was not needed. We have litigated this issue in at least two different circuit courts, the 5th Circuit and the D.C. Circuit, and prevailed in cases brought both by the Independent Petroleum Producers Association, which will follow in the next panel, and by one of its member organizations, the Panhandle Producers and Royalty Owners Association. So it is claims similar to those that have been made in the case that you inquired about.

The CHAIRMAN. All right.

Senator Domenici.

Oh, excuse me. Senator Bradley.

Senator BRADLEY. Mr. Chairman, I do not have any questions for Mr. Schroeder. I thank you for your testimony. Well, maybe I will ask you one. [Laughter.]

Can you imagine any buyer not buying the cheapest gas they could get?

Mr. SCHROEDER. I cannot think of any reason why they would be driven to do otherwise, no.

Senator BRADLEY. So if you are a buyer in the northeast and you buy gas from Canada, it has got to be the best deal you can get, right?

Mr. SCHROEDER. I assume that is the decisions they are making.

Senator BRADLEY. And if there was a better deal somewhere else, you would probably take that, right?

Mr. SCHROEDER. I would think they would.

Senator BRADLEY. So it is a little odd, then, to be saying that the buyer is not going after the lowest possible price, right?

Mr. SCHROEDER. We leave that to the buyer to pursue, yes.

Senator BRADLEY. You know, maybe the most stable price is over a long term contract, right? You would pay a little something for stability of price, right, over a period of time?

Mr. SCHROEDER. We primarily look to the marketability that it will remain competitive in that market over the life of the contract.

Senator BRADLEY. And if you had a long-term contract, that would be some worth if you were planning to plan, right?

Mr. SCHROEDER. Yes.

Senator BRADLEY. Okay. I just wanted to ask you those few questions. Thanks.

The CHAIRMAN. All right.

Senator Domenici.

Senator DOMENICI. I, too, want to thank you for appearing.

While I am not saying this would happen, but let me answer Senator Bradley's question about buying the cheapest gas. If you owned a third of the pipeline and you had to pay for the pipeline, you might not buy the cheapest gas, is that not right? If you were a utility company and you owned a third of the pipeline and you had to pay for that pipeline?

Mr. SCHROEDER. I am not sure—are you talking about an interstate pipeline?

Senator DOMENICI. Well, I am talking about this one.

Mr. SCHROEDER. Which is this one?

Senator DOMENICI. The Iroquois gas facts say that the utilities are going to own a third. I am not arguing that point, that is wonderful. But they are going to have to pay for a third of the pipeline.

Mr. SCHROEDER. I would rather not get into the Iroquois/Brooklyn Union situation, for reasons mentioned in my opening statement.

Senator DOMENICI. Well, then, let me just say, so you understand that, theoretically, if a utility company that is going to distribute gas owns a third of a very expensive pipeline, and they have got to pay for the pipeline and sell the gas, they might not buy the cheapest gas.

Mr. SCHROEDER. They are ultimately going to be accountable to their state public utility commission. And if they are not making a prudent purchasing decision, they do so at their peril.

The CHAIRMAN. All right. Would you yield on that point?

There is a statement, I think, in that Iroquois decision that the finding of your import certificate subsumes the issue of prudence, does it not? Let us see, "a DOE finding that an import is not inconsistent with the public interest subsumes a finding of prudence."

Mr. SCHROEDER. Is that the Brooklyn Union case?

The CHAIRMAN. Yes.

Mr. SCHROEDER. I would rather not talk about that particular case.

Senator DOMENICI. I am not trying to make the case on Iroquois, and let me just drop it. I am trying to get to a completely different point. But I do want to say for the record that many state utilities are prohibited from addressing the issue of federally approved pass-throughs. So if there is a federally approved pass-through for the cost of the pipeline, then we are talking about the commodity price. And that is where the rub may come on buying the cheapest gas.

And let me just ask you a question. I am trying to make the point that you ought to retain jurisdiction under 256 to address different rate structures. And I hope we are not getting rid of that jurisdiction because maybe under duress or otherwise you all have said, under the "as billed" situation, that you retain it.

Now I am just going to use three or four numbers and tell you that it is important. The Canadians are going to do their business this way. They figure the direct, so-called demand charges, and they go through their system, and they come up with one that says it is 42 cents. So I wrote down 42 cents. You might write down 42 cents.

Now the commodity is what is left. And when you do the arithmetic, they know they are going to get 92 cents. So it is 50 for the commodity. So it is 50 plus 42 is 92, because of the way they calculate their fixed costs. We do not calculate fixed costs the same way in the United States. And that is not saying one is right and one is wrong. You happen to know they do them differently.

So ours happens to be 30 on the fixed and 60 on the commodity. You add them and it is 90 cents. For the consumer, the 60 plus 30 is cheaper. But if a utility commission is saying we are only interested in the commodity price, the 50-cent commodity price is cheaper.

That is of great concern to us. We are worried and do not want the authority and jurisdiction to look at the overall system and the way those are calculated, and frankly, if we cannot beat them, we ought to join them, or they ought to join us. Either one. We ought to do it their way or they ought to do it our way. And if we cannot force them to, then we ought to change ours to what we put into the fixed price.

This example is just one I wrote down in pencil, and probably you ought to add 10 or 15 cents to each one for today's market. But this is the kind of thing that concerns me. Not about this particular pipeline at this point, but to make sure that you all are aware of this and you are not abandoning this jurisdiction under some premise of point of sale.

Mr. SCHROEDER. Senator, we are aware of this, and these are terms that are freely negotiated among the parties. In fact, if I look at your example for the domestic side, you know 70 percent of our gas today is not sale for resale, but is transportation gas.

Senator DOMENICI. I understand.

Mr. SCHROEDER. So the purchaser that wants to acquire this gas can go out and negotiate terms and conditions with the producer at the wellhead, in which he could pay a larger demand charge and a lower commodity charge. These are freely negotiated contract terms.

Senator DOMENICI. I understand that. And I do not want to take any more time. I just want to suggest that there are some occasions when, as a matter of fact, the commodity price causes a discrimination against our gas. And we just think you have jurisdiction under 256, and we hope you will look at it when it is called to your attention. I have no reason to think you will not. And nothing you have said here today would indicate you will not. Is that correct?

Mr. SCHROEDER. We look at all the contract terms and try to ensure—or do ensure—that the contract will remain competitive in that market over the life of the contract.

It would be helpful to perhaps provide a little bit of the background or the history for Opinion 256. And that was, as Chairman Allday noted, a sale for resale that was being acted upon by the FERC in its regulation of the rates of an interstate pipeline. In approving the authorization of the import at issue there, the Department of Energy approved the two-part rates, which were the subject of that opinion, in the form in which they were proposed to the Department.

And in fact, the Department encouraged the FERC, although it did not tie their hands, not to reallocate those demand and commodity costs, although the FERC chose to in the exercise of its discretionary functions to regulate that pipeline.

So the Department, even predating Opinion 256—and the specific history of FERC Opinion 256, is that the Department did not choose to reallocate or instruct the parties to reallocate costs within that contract. We found that particular contract to be competitive and to meet the policy of the Department, and we approved it in the form it was presented.

The CHAIRMAN. Senator Murkowski, I might mention that we have closed the season on Mr. Allday. His testimony has been finished, and we invited him to sit at the table. He said he would if we would assure him that there would be no more questions to him. So we closed the season on him, but you are welcome to shoot at Mr. Schroeder.

Senator MURKOWSKI. I do not know whether I could make a deal with you, Mr. Chairman. If I ask one question and nobody else is able to answer it but Mr. Allday, if I stick to one question would you be prepared to make a deal for me? I will not try to make that deal now. I will just ask the question and promise that it is only one.

A little different tack, it is quite apparent to me that the Canadians are finding an expanding market for Canadian gas in the United States. Is that generally acknowledged, gentlemen?

Mr. SCHROEDER. I would say in the Northeast there is an expanding market for gas generally.

Senator MURKOWSKI. If one looks at the prebuild that was built, when, in the late 1970s or early 1980s from Alberta down through Spokane and into Los Angeles and then the other one that was built across a portion of Alberta and goes into the U.S. in North Dakota, you are familiar with that line, and that is, I understand, operating at capacity.

Are you aware of that?

Mr. SCHROEDER. I am not familiar with its capacity.

Senator MURKOWSKI. Is anybody familiar with it? You would nod your head and say——

Mr. SCHERMAN. It is generally operating at capacity.

Senator MURKOWSKI. It is moving a lot of Canadian gas?

Mr. SCHERMAN. Yes.

Senator MURKOWSKI. So one could conclude that the Canadians are indeed finding an expanding market for Canadian gas as evidenced by this proposal on the east coast and the one that has been in existence for some time. Of course, any of you with a little memory will recall that that prebuild was to be very temporary until such time as the Alaska gas could be brought down and the Canadian government and the U.S. Government entered into an agreement and granted licenses.

The Canadian Government maintains that we have a commitment not to utilize Alaska gas for any other purpose than that for which it was originally conceived. Are you generally familiar with that?

Mr. SCHROEDER. Generally familiar.

Senator MURKOWSKI. My question is, then, if there is so much of a market for Canadian gas in the U.S. and it is expanding, why do the Canadians oppose the potential export of Alaska's natural gas to markets in the Far East?

Mr. **Schroeder**. I do not know the reasons for their opposition. I have not dealt with that particular situation.

Senator **Murkowski**. Anybody? Can anyone give an opinion?

Mr. **Scherman**. Senator, we have enough trouble with things directly within our control.

Senator **Murkowski**. Any volunteers in the audience?

Thank you, Mr. Chairman. [Laughter.]

I think I made my point.

The **Chairman**. Thank you very much, Senator Murkowski.

One parting comment, Mr. Schroeder. It would seem to me that DOE would do well to delegate its section 3 responsibility back to FERC so that—[Laughter.]—you could have one forum with one consistent policy. I think it would tend to expedite matters as well. I know Mr. Allday is anxious to have more to do. [Laughter.]

Really, I think it would make for a better policy. It used to be that way, and I think it would make for a better policy. So you can take that back for discussion at DOE.

If there are no further questions, thank you very much.

Next we have a panel consisting of: Mr. Joseph Ramsey, Chairman of the Iroquois Gas Transmission System Management Committee and Vice President of Tennessee New England Pipeline Company, which is a subsidiary of Tenneco Gas; accompanied by Mr. Robert Reid, who is President of Iroquois Gas Transmission System.

Also on the same panel is Mr. C. Paul Hilliard, Chairman of the Board of IPAA in Washington, D.C. He is also Chairman of Badger Oil and Gas Ltd. from Lafayette, Louisiana.

STATEMENT OF JOSEPH RAMSEY, CHAIRMAN, IROQUOIS GAS TRANSMISSION SYSTEM MANAGEMENT COMMITTEE AND VICE PRESIDENT, TENNESSEE NEW ENGLAND PIPELINE CO., ACCOMPANIED BY ROBERT J. REID, PRESIDENT, IROQUOIS GAS TRANSMISSION SYSTEM

Mr. **Ramsey**. Thank you, Mr. Chairman. Iroquois has submitted written comments to the committee, and I ask that those be included as part of the record of the oversight hearing.

The **Chairman**. Without objection.

Mr. **Ramsey**. We appreciate the opportunity to be here today to discuss the Iroquois project and the true facts associated with it. Let me begin with the following.

I truly believe that everyone in this room is sympathetic to the current plight of the gas producers in this country, especially the independents. Their problems are well known: very low wellhead prices; the gas bubble which continues to linger; loss of tax incentives both for the producers themselves as well as for investors who put money into drilling ventures; and all this has resulted in very low drilling rig activities in this country and some serious concerns about the future of gas deliverability from traditional domestic sources.

The fact is the Iroquois project or Canadian imports in general did not cause these problems. Just as clearly, delaying or stopping the Iroquois project will not solve these problems. The U.S. gas industry in general and the producing sector particularly are suffering the painful transition from a heavily regulated environment to more of a free market one, and in this respect our chaos is not unlike that of the airlines or any other industry recently deregulated.

The gas market in this country is on the rebound. It is growing again, and demand has gone up over 2 trillion cubic feet on an annual basis or more than 10 percent in the last three years. The gas bubble is dissipating, and a strong rebound in gas prices, we believe, is imminent.

The rapid growth in markets in the northeast United States are constrained by pipeline capacity. The pipelines to this region stay essentially fully on a year-round basis. It was the combination of full pipeline capacity and strong market growth that led to the filing of the many new projects in the FERC open season. I believe Chairman Allday mentioned there were 72 new total projects for new capacity to serve the northeast.

These filings were supplied by both Canadian and domestic gas, and Iroquois was but one of those filings. The end result of those filings was projects 53 percent supplied by domestic gas and 47 percent supplied by Canadian gas. Many of those domestic projects have been certificated. They are being installed, and in some instances gas is already flowing under these projects to deliver more domestic gas to the northeast.

The need for new capacity and more gas into the northeast were seldom questioned in the past two and one-half years of proceedings in the open season process, and the many, many letters submitted to this committee over the past few days by the market and by local regulators make this point more forcefully than I ever could. Market need at this point should be an absolute given.

Even if a small minority should dispute the market need, the FERC clearly has a huge amount of data and sworn testimony that it has collected over the past two or three years that will allow its staff experts to address this issue without the need for future public debates or hearings.

Let me turn now to the issue of rate design and the so-called level playing field. Opponents of the Iroquois project contend that Canadian gas has an inherent advantage over domestic supply because of differences in rate design policy north of the border versus south.

Let me remind everyone here today of one often-overlooked fact. Those differences in rate design philosophy have existed for decades. The rate design on Canadian pipelines has always been a fixed variable one versus the two-part rates traditionally used on U.S. pipelines.

If the rate design difference creates an inherent advantage for Canadian gas, why does Canadian gas only have 5 percent of the U.S. market? Why are the huge amounts of proven reserves in Canada not being produced today? The reason is because the market, when looking at an incremental supply of gas, looks at all the costs, gas costs, demand costs, commodity costs, fuel costs and so forth, in addition to other considerations like length of contract, security of supply and so forth.

We could argue about the various rate designs all day, but the important point is this is not a new issue. It has been before the

FERC many, many times. There are no new facts associated with it, only new allegations. The FERC clearly has all the information that its technical experts need to address this issue.

Let me close my remarks with a brief discussion of what we think may be the most important issue in this whole debate, and that is timing. The basic elements of the Iroquois project were conceived and negotiated in 1984 and 1985. Willing sellers of gas reached agreement with willing buyers on the basics of gas purchase and supply contracts and the transportation vehicle necessary to consummate the deal. The sellers had other options, and the buyers had other options.

Almost five years later the first cubic foot of gas under the Iroquois project has yet to flow. This project has transited every conceivable regulatory process north and south of the border and has spent almost $30 million in the process. The supply needs of the Iroquois market have become extremely acute as a result of these delays, and without timely approvals in the next few months the gas market could be seriously damaged.

If I could stop for just a second, there was a question earlier of Chairman Allday about whether limited evidentiary hearings will delay this project. I can assure you that they will. The timetable for Iroquois is to go into service November 1, 1991. In order to meet that deadline, we must begin aggressive right-of-way acquisition in July of this year, and we must have an FERC certificate to begin the aggressive right-of-way acquisition. So we are 60 to 75 days away from when we must pursue right-of-way acquisition on our project, and I would humbly submit that the FERC will not be able to hold a limited evidentiary hearing of any kind in 60 to 75 days.

The plain facts are there is no other project available which can meet the Iroquois market needs on anywhere near the same time frame. If Iroquois were to somehow vanish tomorrow, domestic producers would sell no incremental gas into this market for a number of years because there are no readily achievable pipeline capacity projects waiting in the wings in the near term.

We truly believe that, just as a rising tide lifts all ships, growing the market with Canadian gas from this project will benefit domestic producers as well. On that point, it should be mentioned that there are several new domestic projects being formulated today to meet the next increment of market growth after Iroquois. You might say that these projects are where Iroquois was in 1986, and they may be successfully delivering additional domestic gas in 1993 or 1994.

In summary, we believe gas is poised for a very major period of market growth. As our country focuses on a cleaner environment, gas will clearly be the fuel of choice in the coming decade. I would submit to you that we are all better served by getting out and growing this market together.

Thank you.

[The prepared statement of Mr. Reid follows:]

PREPARED STATEMENT OF ROBERT J. REID, PRESIDENT, IROQUOIS GAS TRANSMISSION SYSTEM

Mr. Chairman, my name is Robert J. Reid. I am President of Iroquois Gas Transmission System. I am pleased to accept the invitation to testify before this Committee extended by your letter dated April 19, 1990. Please accept these prepared remarks for the record. In my appearance before the Committee, I will ask that this prepared statement be inserted in the record. I will be accompanied at the hearing by Joseph E. Ramsey, who is Chairman of the Iroquois Management Committee and Vice President of Tenneco Gas, whose affiliate is the second largest partner in Iroquois. Mr. Ramsey will be making the oral presentation at the hearing.

I will cover seven topics in my prepared statement, each of which is identified by a descriptive heading below.

1. THE NEED FOR GAS AND NEW PIPELINE CAPACITY IN THE NORTHEAST

If there is anything approaching a universally accepted truth in this industry, it is that there is a critical need for additional natural gas supplies and incremental pipeline capacity in the U.S. Northeast.

Support for that proposition ranges from DOE's Interim Report On National Energy Strategy, released just last month; to the Gas Research Institute 1989 *Baseline Projection of U.S. Energy Supply and Demand;* to numerous policy statements by Northeast state governments (e.g., the New England Governor's Conference *Analysis of the Impact of Increased Natural Gas Use in the New England Region,* adopted by all six New England Governors last month, and the New York *Energy Plan* published May 1989); to the outcome of the Federal Energy Regulatory Commission ("FERC") "open season" process; to the Final Report of the Chief Administrative Law Judge issued on November 30, 1988; to the specific findings in the various proceedings before the Department of Energy ("DOE"), National Energy Board ("NEB") and the New York Public Service Commission ("NYPSC") regarding the Iroquois project. I would also call the Committee's attention to the letter recently delivered to the Committee by the principal Iroquois shippers, which summarizes very clearly their needs for incremental gas supplies and pipeline capacity.

Indeed, the lesson of last December's extremely cold weather was that without new, long term gas supplies and, more importantly, incremental pipeline capacity to serve the Northeast, the region will be unable to meet current peak requirements for natural gas, let alone long-term and annual requirements.

On top of all of this are the Clean Air Act amendments which are working their way through the Congress. One major thrust of those amendments is the need to increase reliance on natural gas for power generation purposes. That need is particularly acute in the Northeast, where there is an urgent requirement for new generating capacity at a time when air quality and acid rain concerns are at a peak. The only reasonable solution for the Northeast is to utilize natural gas for power generation to the maximum extent possible, and the only way to do that is to develop new sources of supply and new pipeline capacity, such as represented by the Iroquois project.

In the face of these incontrovertible facts, it is startling and ironic to find that the Independent Petroleum Association of America ("IPAA") is advocating more regulatory procedures to examine the issue of need, while at the same time asserting the right to compete for the market.

Today, 95% of the gas supplied to the Northeast is from domestic sources. The domestic producers are also playing a large role in serving the incremental needs of the Northeast—indeed, 50% of all volumes involved in the "open season" settlements are domestic. However, there is a practical barrier to any further penetration of domestic gas into the Northeast, namely the absence of significant new pipeline capacity dedicated to the Northeast. And that is precisely the role Iroquois plays.

While Iroquois is dependent on shippers who have made long-term supply arrangements with Canadian producers, that kind of support is essential for financing major new pipeline construction. For a number of reasons, the domestic producers are unable to provide such support. Nonetheless, once the Iroquois capacity is constructed, it will immediately open new opportunities for domestic producers to serve the Northeast.

In light of the clear need for new gas supplies and pipeline capacity in the Northeast, I will discuss briefly the history of the Iroquois project, the FERC "open season" and Iroquois-related regulatory proceedings and then the primary issue addressed in the Chairman's April 19 letter—the issue of whether Iroquois should be subject to trial-type evidentiary hearings.

2. BRIEF HISTORY, STATUS AND TIMING OF IROQUOIS

Iroquois began in 1985 as the third phase of a continuing effort to provide increased gas service to the Northeast by tapping Canadian reserves. The first two phases, consisting of a total of 92.5 MMcf/d, are the Boundary Gas volumes, which represent the only LDC direct purchase Canadian gas now flowing into the Northeast market.

The Canadian initiative began in 1979 because, in the judgment of state and federal regulators and LDC's, the growing long-term needs of the Northeast market could not be met without access to Canadian gas. Almost all U.S. pipelines were in curtailment at that time.

In turning to Canadian gas, the project sponsors did not then and do not now intend to displace domestic gas supplies; the objective was and is to use Canadian gas for incremental needs which domestic producers could not meet.

Iroquois' FERC application was filed in May 1986. Shortly thereafter, Iroquois and its shippers initiated related proceedings at DOE, NEB, the Corps of Engineers ("COE") and various state agencies.

In 1987, FERC initiated the unprecedented "open season" proceeding which provided any interested party—including domestic gas interests—an equal opportunity to propose service to the Northeast.

Out of the "open season" process came a wide variety of proposals, involving both domestic and Canadian gas. The Canadian/domestic split for the new projects was about 50/50. With a few exceptions, the domestic projects have been certificated and many are already in service. The Canadian projects, on the other hand, are still awaiting final regulatory approvals.

Iroquois entered "open season" as a project designed to serve 11 LDC's. It emerged as a project designed to serve 17 LDC's and 4 power generators.

Iroquois entered "open season" as a partnership of 7 companies. It emerged as a partnership of 13 companies, representing the broadest possible array of U.S. and Canadian interests. There are 2 Canadian partners and 11 U.S. partners, including 4 major domestic interstate pipelines, 5 large LDC's, the New York Power Authority and a large energy project developer.

The "open season" settlement occurred on November 30, 1988. By that time, Iroquois had already undergone three years of environmental review at both the state and federal levels.

Since that time, we have undergone an additional 17 months of regulatory and environmental review at FERC, DOE, COE and before various state agencies.

The proposed in-service date is November 1, 1991. That date is critical for two reasons: first, the gas is required for the 1991 winter heating season and, second, the major Canadian gas export licenses supporting the Iroquois project—which were granted in 1987—expire if gas it not flowing on or before October 31, 1991. In order to meet that date, we must complete all regulatory reviews and commence right-of-way acquisition this summer, complete our financing this fall and commence actual construction in early 1991.

If we achieve our critical in-service date, it will have taken 5½ years from filing our application to commencement of operations. At a time when clean-burning natural gas is the consensus fuel of choice, that is an extraordinarily long time.

3. THE SCOPE OF THE REGULATORY PROCESS

It is safe to say that the Iroquois project has been subjected to the most thorough and intense regulatory and environmental review ever accomplished for a gas pipeline project.

The Iroquois project itself, the related Alberta Northeast Gas, Limited ("ANE") gas supply project and the TransCanada facilities expansion in Canada have to date been the subject of:

—4 years of proceedings before FERC

—4 years of proceedings before DOE's Economic Regulatory Administration and its successor, the Office of Fossil Energy

—3½ years of proceedings, including extensive evidentiary hearings, before the NYPSC governing both environmental compatibility and public need

—3½ years of proceedings before the COE

—4 years of proceedings, including extensive evidentiary hearings, before the NEB.

Some of these proceedings are completed; others are ongoing. Completion of all ongoing proceedings in the near term, in accordance with the schedules which the regulatory agencies have set on the public record, is critical to the project.

Including the extensive environmental and economic data and applications filed with these agencies, the combined records in these regulatory proceedings measures more than a million pages. Iroquois alone has expended $25 million on these regulatory and environmental review processes.

Part of the extraordinary record on this project stems from the fact that, as with any major energy project, there has been opposition—some of it very intense. However, an equally significant factor is that governments at all levels have approached their obligations with utmost seriousness and have dedicated their resources to the most thorough review possible.

Indeed, Iroquois is a better project today because of the extensive review process. THE ONLY CONCEIVABLE REASON FOR SUBJECTING THIS PROJECT TO STILL FURTHER HEARINGS AND REVIEW WOULD BE A THINLY VEILED ATTEMPT BY OUR OPPONENTS TO DELAY IT AND ULTIMATELY TO KILL IT.

4. THE EVIDENTIARY HEARINGS ISSUE

A primary focus of this Committee's oversight hearings is why FERC and DOE have not held trial-type evidentiary hearings on issues raised by opponents of the project, like IPAA.

As the Committee well knows, FERC and DOE have long disfavored trial-type hearings in certificate and import authorization cases because the only principal products of such hearings are usually high legal bills and significant delay.

Except in extraordinary cases where trial-type hearings are clearly needed, FERC and DOE both favor written hearings, where all parties are given opportunities to submit evidence in writing and to respond to the evidence submitted by others. That is the procedure FERC and DOE have followed here, and all parties (including IPAA) have had numerous opportunities to put their views and their evidence before FERC and DOE, both in writing and orally.

This policy favoring written hearings is completely consistent with the Natural Gas Act and has been repeatedly acknowledged by the Commission and the courts to be appropriate. I would refer the Committee to several cases which establish this point: *El Paso Natural Gas Company,* 448 FERC ¶ 61,202 at 61,756–57 (1989); *Wisconsin Gas Company v. FERC,* 770 F.2d 1144, 1165–68 (D.C. Cir. 1985); *Amador Stage Lines, Inc. v. United States,* 685 F.2d 333, 335 (9th Cir. 1982); *American Public Gas Association v. Federal Power Commission,* 567 F.2d 1016, 1064–67 (D.C. Cir. 1977).

Iroquois' position is that the written hearing procedures applied to it have been comprehensive and fully adequate to elicit all relevant positions and evidence. Despite repeated opportunities, even the most staunch opponents of Iroquois, like IPAA, have failed to demonstrate that their positions warrant trial-type hearings.

The two issues which have drawn the most attention in terms of calls for trial-type hearings are the need for the Iroquois pipeline and the IPAA "'anticompetitive rate structure" issue. Both issues are mentioned in Chairman Johnston's April 19, 1990 letter to me and I will address each of those issues separately.

5. NEED

I have addressed the question of need at the outset of my statement and will comment on it only briefly here.

There are two parties which have directly called the need for additional long-term gas suplies in the Northeast into question. One is the Fuel Oil Dealer Associations, whose primary goal is to keep *any* new gas supplies out of their markets, regardless of source. The other, quite ironically, is IPAA.

As I noted before, I find it difficult to understand how IPAA can, on the one hand, assert its right to compete for the incremental Northeast market while at the same time arguing that the need for additional gas supplies in that market is in question. Certainly, IPAA raised no objections regarding the need for the domestic projects which emerged from the "open season."

Regardless of the tactics employed, the fact is that one could not imagine a more complete and convincing record on the issue of need for the gas supplies to be delivered by Iroquois. That issue has been considered in trial-type hearings by the NYPSC and the NEB and has been decided overwhelmingly in favor of need. The issue has also been considered by DOE after extensive written evidence has been filed, and again the finding was overwhelmingly in suport of need. As noted above, a number of studies by impartial bodies confirm the need for incremental gas supplies and new pipeline capacity to the Northeast. I would ask the Committee to take particular note of the *Analysis of the Impact of Increased Natural Gas Use in the New England Region,* adopted in April 1990 by the six New England Governors, which deals specifically with the Iroquois project and states that Iroquois "is anticipated to be on-line by the fall of 1991."

In terms of Iroquois' markets specifically, the record before FERC and DOE is comprised of thousands of pages of data generated, not by Iroquois, but by the 21 companies whose gas will be shipped on Iroquois. These data show that the need for all of the gas to be transported by Iroquois exists right now. In all cases, the Iroquois shippers have backed up their data with signed contracts for gas supply and for all necessary upstream and downstream transportation. Not one party has demonstrated that these data are inaccurate or that there is any need for expert testimony to further test the data.

Chairman Johnston's letter asks me to comment on whether other existing or planned interstate pipeline projects could serve the Iroquois markets in lieu of Iroquois. With all due respect, that was what the FERC "open season" was all about. Many proposals were advanced to serve the market proposed to be served by Iroquois. The specific question addressed by the parties was: which project best served the needs of the market? The clear answer was that Iroquois best serves those needs and should be built. In short, the functions served by Iroquois cannot be served by any other pipline—existing or planned—particularly now, when the need for gas is critical.

6. THE ANTI-COMPETITIVE RATE STRUCTURE ISSUE

IPAA's assertion is that, because the NEB requires TransCanada PipeLines to design its rates on a basis which results in a higher demand charge and lower commodity charge than would be the case if U.S. ratemaking methodologies were applied at TransCanada, Canadian gas enjoys a competitive advantage in the U.S. market.

The short answer tc IPAA is that there is no merit whatsoever to their argument. There has never been a shred of evidence, in the legal sense *or* in the real sense, that the way the NEB regulates TransCanada creates a competitive advantage for Canadian gas or that Canadian gas is in fact displacing domestic gas because of its hypothetically lower commodity cost. Indeed, since the Boundary Gas project started delivering Canadian gas to the Northeast in 1984, domestic deliveries into the Northeast have increased significantly, not decreased.

IPAA repeatedly points to FERC Opinion 256 and FERC's recent *Pacific Gas Transmission* decision to indicate that FERC has recognized a competitive "advantage" for Canadian gas. But as FERC and DOE have repeatedly pointed out, Opinion 256 and the PGT decision deal with an entirely different issue—they do not deal with projects, like Iroquois, where Canadian gas is being purchased and imported directly by LDCs and power generators, rather than by "merchant" pipelines whose function is that of a middleman. I would note that the structure of the Iroquois project reflects the very essence of FERC's open access transportation policy—a policy strongly supported by IPAA and its members.

The other important point is that IPAA has been asserting this very position against Canadian gas for over four years. Every agency and every court—including the U.S. Court of Appeals—which has addressed the issue has found that it has no merit. The most recent pronouncement on the subject is found in FERC's recent approval in principle in the Niagara Import Point Settlement ("NIPS") proceeding [Tennessee Gas Pipeline Company, et al.,] Docket Nos. CP88-171-000 et al. (April 11, 1990)], which spells out clearly and concisely why IPAA is wrong.

Having lost their case *on the merits* in every relevant judicial and regulatory forum, IPAA now turns to this Committee for assistance in forcing still further proceedings on this issue. With all due respect to this Committee's role, it should not second-guess FERC, DOE and the courts on this matter. Nor has IPAA given it any reason to do so.

7. CONCLUSION: THE REAL ISSUE

We believe the issue here is not the legal question of whether trial-type hearings are required at FERC or DOE.

The issue is whether independent domestic producers are going to succeed in placing roadblocks in front of a major project involving importation of Canadian gas.

While IPAA may vigorously deny it, those are the facts. And their motivation is very clear: the independent domestic producers who support IPAA's efforts here recognize that, for them to keep Canadian gas out of the incremental Northeast markets *legitimately,* they will have to agree to sell gas on a long term basis—10-15 years—at prices which are competitive with alternative fuels. They simply have not been willing to agree to the terms required to sell gas into a competitive market.

Given their unwillingness or inability to compete, IPAA's fallback is to attempt to kill this Canadian project in the hope that the market will increase the price it is willing to pay for their domestic gas.

I realize that I have been blunt, but the importance of the subject requires it. The real issue is not the need for gas or the NEB's ratemaking policies in Canada—the issue is the unwillingness of certain independent domestic producers to face the realities of the marketplace.

Again, I urge this Committee not to nurture IPAA in this destructive strategy. Indeed, to do so would violate both the letter and the spirit of the U.S.-Canadian Free Trade Agreement and the fundamental notion that regulatory bodies must be permitted to conduct their quasi-judicial functions free of interference from the other branches of government.

The Northeast needs long term Canadian gas supplies. The market has decided that the Iroquois pipeline is the most appropriate means of delivering the next increment of gas supplies competitively to the city gates of the LDC's and to the power generators which serve the Northeast market. Iroquois has spent $25 million and over 4 years transiting the regulatory process at every level in both countries, developing a comprehensive record that will stand up to any legal challenge. Now is not the time for this Committee or anyone else to throw a wrench into the works.

We appreciate the Committee's assistance in allowing us to put the facts before you.

The CHAIRMAN. Thank you very much.

Mr. Hilliard.

STATEMENT OF PAUL HILLIARD, CHAIRMAN OF THE BOARD, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Mr. HILLIARD. Gentlemen, I appreciate the opportunity to be here today. My name is Paul Hilliard, I am President of Badger Oil Corporation, and Chairman of the Independent Petroleum Association of America.

I want to assure Senator Bradley that there is no reason to be intimidated by a bunch of broke independents. We are not in a position—we are trying to survive right now, we are not in a position to intimidate anyone.

We filed a lengthy written statement, and I did want to make a few comments and reference the map that we have put up over here.

Natural gas is a unique substance. It is invisible until you set it afire. It is soundless unless it is in motion and under pressure. And it is odorless unless you add a chemical or mix it with money and politics, then it has a definite aroma. [Laughter.]

When it leaves the wellhead, it goes back underground and it stays underground until it appears as that bright blue flame at the burner tip. Now it is no doubt a physical necessity that natural gas travel underground since it is highly flammable and under 1,000 pounds of pressure per square inch. But it is also conceded that the interstate pipelines who transport it and the LDCs—and those are not lesser-developed countries—those are local distribution companies, who distribute it, need to be subject to Federal and state regulation of various sorts.

You certainly would not want an invisible, flammable, valuable substance such as natural gas running around the country underground and unfettered by Government regulations. As we all know, Government controls ensure safety, efficiency, fairness, reliability, adequacy of supply, and all those other good things we have come to expect from Democratic bureaucracy.

Now this hearing about Canadian gas imports, and the regulatory process approving those imports, and the disparate transportation rate structure in Canada, vis-a-vis the U.S., is what it is all about. Hopefully, one of the objectives of this hearing is to pull those pipelines and their contents out of the ground and examine them in the clear light of day. That examination should be interesting.

If you will focus on the map, you will see the distances from Alberta to the northeast, vis-a-vis the distances from the Gulf Coast and the southwest to the northeast. And what I submit is that Iroquois cannot pass the duck test. It looks more expensive, it smells more expensive, it feels more expensive, and I suggest that it is more expensive.

And to build that $3 billion to $4 billion total system that they are talking about, which is the combination of Iroquois and the various phases of NIPS, when you can add looping or compressors and bring gas from 1,000 miles less distance in the Gulf Coast and the southwest, to me, does not make too much economic sense. The consumers should be interested in those formulas.

The Arkoma line, for instance, is now being built to move gas from the Arkoma Basin eastward, and hook it into the pipelines to the northeast. And although we have heard various stories about the tremendous growth in demand in the northeast, and while we look forward to serving that increased growth, it is not as exciting as it seems when you look at the actual numbers.

Now the FERC decision in the NIPS case, or Niagara, was not at all surprising, since we had been hearing for several weeks that we would be zapped in that case, and that the pressure to approve NIPS as a prelude to approving Iroquois was heavy and probably irresistible.

The name Niagara adds a special note of interest to this case. I recall come punster once characterized Niagara Falls as the second biggest disappointment to millions of American honeymooners. And as I watched the videotape on the April 11th NIPS decision by the FERC, it occurred to me that while independents in the U.S. had not exactly sought nor expected a honeymoon for us at Niagara, neither did we expect we would be butchered and sent over the falls in a barrel.

Contrary to what the pundits say, watching that tape is much worse than watching sausage being made.

We think FERC evaded its responsibilities to ensure fair play and used extra record evidence to drill U.S. independents into the ground in the NIPS decision.

Now due process is one of the basic ideals that America is all about. A wise man said, "America is the only place in the world where process is more precious than product." Now have these proposed multi-billion-dollar import projects been subject to the due process system with a full-scale hearing, evidentiary hearings, cross examination of witnesses and so on? We do not think so. At least not since the real numbers on their costs have begun to surface.

The open season process never looked at $3 billion to $4 billion in costs for NIPS and the Iroquois, vis-a-vis proposals by domestic pipelines to add facilities as needed to meet incremental demand growth in the northeast.

Was the process ever opened up for full-scale presentation, argument and cross examination on the disparate rate structure and the ultimate consumer costs of competing systems?

Now I note that Tennessee is testifying today, although the statement submitted by Iroquois was written by Mr. Robert Reid, who is President of Iroquois. Obviously, these big pipelines and distributors can afford both actors and script writers, since they can put both those costs into their rate base.

Now Tennessee started out violently opposed to the Iroquois project. Some time during the preliminary rounds of open season, either Tennessee or Iroquois saw the light, got religion, and now Tennessee is point man on the project. Now since the Tennessee briefs filed earlier on this Iroquois project are so incisive and persuasive, we would ask that you hold this hearing open for 30 days so that we might supplement the record with some of those brilliant arguments put forth when Tennessee was anti-Iroquois.

We also have some other items on different aspects of this subject, which we would perhaps like to insert in the record.

Mr. Reid's statement is very well done and, except for his facts, I find it most interesting. His recitation of the time and effort and money spent on this project to date is overwhelming. We wonder where all that money went.

The money spent for legal fees, public relations and government relations alone would drill enough gas wells to meet demand in Massachusetts for the next 10 years. That $25- plus million Iroquois spent to date should definitely add aroma to that cleanest and most efficient of all fossil fuels.

And a lot of that time and a lot of that money, of course, was spent avoiding an open hearing on the merits of Iroquois.

I have been an independent for 35 years, and I have been in lots of bad deals, and I have drilled a lot of dry holes. Now I have also carried around some doggie deals for three to four years, and spent a lot of time and money on them. I have had potential investors tell me, Hilliard, that deal is so doggie you ought to be wearing handlers gloves. Iroquois needs handlers gloves.

They needed to put together 18 partners, including all those distribution companies, to make the deal fly. The response I received on those semi-lifetime deals of mine is this: businessmen do not evaluate a deal based on how long you worked on it, or how much you spent on it. Not in the real world of commerce and industry they do not. What matters is, how does this deal compare to competing deals.

We do not get paid by the hour or by the page, we get paid by the barrel or the MCF. And I have been told by a astute, successful businessmen that if it takes 30 electric logs, four cross sections, nine seismic lines, and 40 pages of numbers, to explain a deal, it has got to be a real turkey.

Now the PSE&G of New Jersey thinks the Iroquois deal is dumb, and they are going to take about 1 percent of their needs from Iroquois. They do not understand the distance on the map and why it is a better deal if you bring it a 1,000 miles further, how that helps the consumers in the northeast.

Now when the consumers want a bright blue flame when they flip the switch, and they want it at the lowest possible price, and they want it without fail, they do not care about pipeline rates or BTU content or FERC 500, or even 256 or NIPS. And they sure do not want any Indians. This hearing is about gas. But it is really about money. And you remember Will Rogers said, "If a guy says it is the principle, not the money, you can bet it's the money."

Now the Iroquois, in their early history, were cannibalistic. After treatment by the Jesuits in the early 18th century, they discontinued cannibalism and became merely scalpers on the side of the British, both prior to and during the Revolutionary War. Hopefully, gentlemen, this hearing will determine if Iroquois has reverted to cannibalism or is merely continuing their propensities to scalp Americans.

I thank you.

[The prepared statement of Mr. Hilliard follows:]

STATEMENT OF PAUL HILLIARD, CHAIRMAN, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

I. INTRODUCTION

Mr. Chairman, I am Paul Hilliard, President of Badger Oil Corporation and Chairman of the Independent Petroleum Association of America (IPAA). I am pleased to accept your invitation to testify about the unfair treatment suffered by domestic natural gas producers in competition with imported Canadian natural gas because of our own government's policy. I come before this Committee on behalf of IPAA and on behalf of 42 national, state, and regional domestic petroleum industry associations. I ask that these prepared remarks be accepted for the record.

The IPAA represents domestic independent crude oil and natural gas producers. Independents operate in all 33 oil and natural gas producing states, drill about 85 perent of all U.S. wells, account for about 40 percent of domestic crude oil and about 60 percent of natural gas production. The primary revenue center for the U.S. independent is the sale of crude oil and natural gas at the domestic wellhead. We reinvest our capital in the search for additional domestic reserves; we are not diversified we just drill for oil and gas.

The purpose of my testimony today is to bring to your attention the failure of the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) to permit IPAA and other parties to present evidence of undue discrimination caused by certain anticompetive pipline projects and to show that cheaper domestic alternatives exist. IPAA has been unreasonably deprived of an opportunity to present evidence and to cross examine promoters of Canadian natural gas imports on the consequences of such projects for domestic consumers and natural gas producers. This is not a trivial matter. The Iroquois Gas Pipeline System (Iroquois) project, when considering both the Canadian and the U.S. facilities, represents over 3 billion dollars of investment in facilities in Canada and the United States. That makes Iroquois one of the most expensive pipeline construction projects in decades. The other large pending Canadian-supplied project, proposed by Tennessee Gas Pipeline Company and others (known as NIPS), is worth up to another billion dollars. If approved, these combined projects will be importing over one billion cubic feet per day within the next few years into the same market area, the Northeast United States.

Because of the difference in rate design methodologies in Canada and the U.S., these projects can be expected to operate at maximum throughput 365 days per year with devastating consequences for U.S. producers currently serving these markets. Independent producers have suffered disastrous economic setbacks over the past five years. In the last half of the 1980s domestic independent oil and natural gas producers suffered a record-breaking decline in drilling activity brought about by collapsing oil and natural gas prices and the abrogation of most long-term contracts with natural gas pipeline purchasers. One measure of the devastation experienced by independents during this period is that membership in IPAA went from 10,000 in 1984 to less than 6,000 today. These unfairly structured import projects could represent a death blow to many producers already crippled by wellhead prices significantly below the replacement cost of gas. I have attached tables to this testimony in Exhibit A showing the dramatic decline of the domestic oil and natural gas industry.

You have asked that I address four specific subjects. I will attempt to address each of these issues in a generic way, rather than focus on the merits of particular cases, because this is a generic problem involving the importation and transportation of Canadian natural gas. Your April 19 letter raised the following issues: 1) FERC's statutory duty under the Natural Gas Act to set contested certificate applications for hearing and whether the issues which intervenors have raised in a particular case are the types of issues which should go to hearing; 2) A particular DOE order conditionally authorizing imports of Canadian natural gas and DOE's rejection of applications for rehearing of that order as premature; 3) Arguments that the contractual arrangements and/or rate design for the upstream transportation and sale of Canadian natural gas provides an unfair competitive advantage over domestic natural gas; and 4) The extent to which domestic natural gas supply Northeast markets and the extent to which existing or planned pipeline capacity is adequate to serve the peak day needs of these markets.

II. A BRIEF STATEMENT OF THE PROBLEM

In its consideration of major certificate applications filed under NGA Section 7(c), like NIPS/Iroquois, where the projects ultimately entail construction of about $4 billion in new facilities, FERC has a duty to examine in an evidentiary hearing those aspects of the applications contested by a party who raises serious issues of material fact. One of the most important issues which should be tested in an evidentiary hearing is the overall economic feasibility of the project. Another issue is whether there may be demonstrably cheaper alternatives.

As I will demonstrate, the rush to judgment by DOE and FERC prevents a realistic examination of the economic feasibility of these projects and precludes domestically supplied interstate pipelines with proposals currently on file from showing that they could serve the needs of the Northeast market at a lesser cost in a timely fashion. Furthermore, even though Iroquois is seeking FERC approval prior to the end of June 1990, its project is not economically feasible, by Iroquois' own admission, unless the National Energy Board (NEB) of Canada decides to ask Canadian consumers to subsidize TransCanada's $2.6 billion construction project. The real reason Iroquois is attempting to strong-arm certificate approval by FERC before the end of June 1990 has nothing to do with construction schedule constraints. It has to do with the contract with the producers in Alberta. Absent FERC approval by August 1, 1990, the producers in Alberta have a right to vote again on whether to supply the Iroquois volumes. Unlike the earlier, favorable vote, this vote would be taken in light of the $2.6 billion construction cost on TransCanada, a cost which producers may bear in substantial part. That is why Iroquois wants to force a premature decision by the U.S. Government.

Neither DOE nor FERC was informed of the $2.6 billion price tag for TransCanada's expansion, 90 percent of which is dedicated to serving Iroquois, until February of this year, almost a month after DOE approved the related Iroquois import authorizations!

Under FERC's "open season" process, in 1987-88 FERC invited all competing pipelines to submit applications to serve Northeast markets. But, FERC's Northeast "open season" was closed in January 1988 and a decision was rendered by FERC long before the true cost of the Canadian facilities was made public. The NEB is not expected to rule until the end of 1990 on whether to force Canadian consumers to subsidize Iroquois. Thus, Iroquois, which has already bootstrapped DOE approval of its proposal, is now pressuring FERC to rush to judgment before the NEB has even determined whether Canadian consumers should pick up part of the costs of facilities dedicated to serving the Northeastern United States. Iroquois (and TransCanada, its major stockholder) are desperate to avoid another vote by the Alberta producers who now know the true cost of the TransCanada expansion. But Iroquois also needs premature aprovals by DOE and FERC in the bag for another reason: to put the NEB in a position of having either to kill the project or force Canadian rate payers to subsidize it.

This cart-before-the-horse strategy has perverted the hearing procedures normally followed by FERC and created a self-imposed deadline which will, if successful, result in FERC approval of this project six months before the Canadians have decided whether it is even economically feasible.

A. IPAA's evidence

IPAA has participated in many cases involving Canadian natural gas imports. Recently, IPAA proffered expert testimony contending that approval of certain pending applications would place domestic natural gas producers at a competitive disadvantage compared to Canadian producers. An example of such expert testimony is the study of U.S. and Canadian Pipeline Ratemaking prepared by Prather Energy Consultants, Inc. (Prather Study) attached as Exhibit B.

The Prather Study irrefutably demonstrates the unfairness of the rate structures proposed by the Northeast project sponsors. In essence, if these multi-billion dollar proposals are completed to the Northeast, the result will be excess pipeline capacity to that area. Domestic independents would not object to these projects if they would permit the market to shift between Canadian and domestic gas supplies from time-to-time based on the price of natural gas. However, these proposals will not permit such market-based purchasing decisions by Northeastern consumers. Instead, the rate structures of these projects in Canada and the United States will squeeze-out competitively priced domestic gas to the extent necessary to assure full utilization of the new facilities. The Prather Study is so convincing on this point that Mr. C.G. Edge, former Chairman of the NEB wrote us an encouraging letter (attached as Exhibit C) endorsing our efforts to "impel the FERC and the NEB to adopt rate designs more appropriate to a competitive North American market."

The fact that Iroquois' customers own about one-third of the pipeline's equity is a further incentive to keep that project filled to capacity by swinging off domestic production, even when domestic gas is less expensive. Thus, the domestic suppliers of natural gas which have served the Northeast for decades will become mere "swing" suppliers to the region.

B. Reaction from DOE and FERC

Despite IPAA's offer of proof, both DOE and FERC have failed to accord domestic producers adquate procedural due process in the form of a hearing where we could further demonstrate our competive disadvantage and the harm to the public interest. All we requested and now request is a fair trial and an opportunity to place into evidence the expert testimony which we believe proves that domestic producers are disadvantaged by current DOE and FERC policies. We also hoped to show the feasibility, under approriate rate design methodologies, of constructing less expensive domestically-supplied facilities to serve the Northeast. In the alternative, we have suggested several different conditions which could be attached to any such authorization and which would prevent undue discrimination.

We have met with no success. This is surprising since domestic producers seek only the opportunity to compete on a fair and equal basis, and have not sought and do not seek any advantage over imported supplies. Domestic producers do not oppose Canadian natural gas imports. To the contrary, we see the existence of Canadian natural gas reserves as desirable because it increases overall consumer confidence in natural gas. But, just as we seek no advantage over our Canadian competitors, we seek to remove any regulatory prejudice favoring construction and operation of Canadian-supplied pipelines. In other words, we want the market to decide whether to purchase domestic or Canadian natural gas.

For the market to be able to make a rational choice, however domestic and Canadian natural gas must arrive at the "city gate" (the point where interestate pipeline facilities interconnect with facilities owned by a local distribution company) with a similar allocation of costs between the demand and commodity components for transportation from the wellhead to the city gate. Under such circumstances, I am confident that domestic natural gas would provide for all reasonably projected base-load needs in the Northeast and imported Canadian gas would make its contribution as a swing supplier or as a supplier of incremental demand.

You need only glance at a map (like the one attached as Exhibit D) to see that domestic natural gas, not Canadian, is the most reasonable choice for the Northeast. Why are the DOE and FERC creating a structure which will guarantee that Canadian gas is used as a base-load supplier in the Northeast?

III. LACK OF PROCEDURAL DUE PROCESS AT DOE AND FERC

DOE, FERC, and the proponents of Canadian import projects have failed to address the concerns of domestic natural gas producers on their merits.

A. The problem at DOE

IPAA has submitted evidence and has disputed key material facts in import-related cases before both DOE and FERC. DOE has consistently rejected IPAA's protests and requests for establishment of hearing procedures in import cases. Since DOE first removed FERC's import/export jurisdiction under Natural Gas Act Section 3 and took direct control of such matters in 1977, DOE has never set an import authorization for hearing before an Administrative Law Judge.[1] Regardless of whatever anticompetitive contract terms may be involved, DOE has never seen an import application it could not approve, as long as the price term is "competitive." (For example, contracts calling for excessively high demand charges are permitted, so long as there is some opportunity for renegotiation in the future.) DOE has rejected IPAA's proposals to eliminate discrimination against domestic natural gas. DOE has refused to apply Opinion No. 256 [2] principles to import proposals seeking to implement two-part, demand-commodity border prices. DOE has refused to condition its approval of import authorizations upon FERC permitting domestic U.S. pipelines to implement rates competitive with rates which would be charged under the import proposals. DOE has refused to give us a hearing. Instead, DOE has relied on FERC to correct any undue discrimination through implementation of changes in the structures of domestic pipeline rates.

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[1] In certain early liquified natural gas (LNG) import cases, the Administrator of Economic Regulatory Administration did sit to hear testimony personally. Under Section 402(d)(1) of the DOE Organization Act, 42 U.S.C. § 7172(d)(1), FERC has jurisdiction to hear any matter within DOE's jurisdiction "involving any agency determination required by law to be made on the record after an opportunity for an agency hearing."

DOE also failed to follow its own procedural regulations with respect to our application for rehearing of a recent conditional Canadian natural gas import authorization. DOE's procedural rules expressly provide for rehearing of "conditional orders." *See* 10 C.F.R. § 590.501 (1989). However, when IPAA filed a petition for rehearing of Opinion and Order No. 368, which authorized importation of up to 397 MMcf/d for the Iroquois project subject to completion of an environmental review, the petition was returned to us by DOE on the grounds that it was improper to seek rehearing of a conditional order.

B. The problem at FERC

FERC, for its part, recently appears to have taken the view that either the United States-Canada Free Trade Agreement binds its hands or that DOE's approval of the import authorization makes it impossible for FERC to examine the anticompetitive impacts of elements of transactions which are upstream from the domestic interstate facilities under its jurisdiction. Domestic producers, who seek only a level playing field, have been completely frustrated in our attempts to get a fair deal from our own government. DOE says it is a FERC problem and then FERC says it is up to DOE and throws in the Free Trade Agreement to boot! The result is that discrimination against domestic natural gas producers is allowed to continue.

FERC's latest gambit in this shell game is to invite us to participate in at least 33 individual domestic pipeline rate proceedings in an attempt to persuade FERC to change the way it structures pipeline rates.[3] Such a task is far beyond our meager resources, since each case can last seveal years and full participate in each complicated pipeline rate proceeding requires an average expenditure of about $100,000. Such an effort would cost IPAA about $3.3. million, an amount almost equal to our entire annual budget. That such a case-by-case effort is far beyond our financial capabilities is no one's fault and we are not crying about it. It is just a fact. Another fact is that FERC knows that, under such circumstances, *nothing* will be done and Canadian-supplied projects will continue to enjoy unduly discriminatory advantages over domestically supplied alternatives. Given the state of the domestic natural gas production industry, one would think that this would be of interest to a government currently attempting to develop a comprehensive "National Energy Strategy."

[This page break is due to a printing error.]

C. The harm to domestic producers continues

History is repeating itself. In 1984 and early 1985, several Canadian suppliers amended their contracts to provide for a two-part demand-commodity border price. (Prior to this time, the gas was imported under a one-part, commodity-only rate which reached as high as $4.94/MMBtu). When pipelines, such as Natural Gas Pipeline Company of America filed in 1985 to seek "as billed" treatment of this gas, consumer groups, state regulatory commissions and domestic producers were compelled to intervene before FERC to eliminate this competitive advantage. FERC remedied this practice in Opinion No. 256, issues on December 8, 1986. However, IPAA has had to continue its battle case-by-case to get Opinion No. 256 principles applied in individual pipeline rate proceedings, with FERC deciding to apply this remedy on the Pacific Gas Transmission system only as recently as January 24, 1990. In the meantime, Canadian gas has enjoyed a marked competitive advantage and the Canadian-supplied Northeast projects represent an end-run around the principles of Opinion No. 256.

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[2] 37 FERC 61,215 (1986), known as the "as-billed" decision.

[3] *See* Policy Statement Providing Guidance with Respect to the Designing of Rates, 47 FERC 61, 295 (1989). The Policy Statement covers 30 pipeline rate proceedings. Three more were added late. Almost one year later, FERC has implemented no significant changes in the way domestic pipelines structure their rates.

Mr. Chairman, DOE and FERC have been so anxious to avoid a discussion of this problem on the merits and to examine appropriate, *timely* remedies that I will be very surprised if the testimony submitted by any of the other witnesses before you today addresses the merits at all. Instead, I feel confident they will continue to hide procedural mumbo jumbo while the shell game continues.

IV. NEW BARRIERS TO FAIR COMPETITION

The Commission has recognized that Canadian costs should be treated in the same manner as domestic costs regardless of how those Canadian costs are billed by the Canadian supplier. FERC has taken remedial action to assure similar treatment for Canadian and domestic costs primarily with respect to setting natural gas sales rates for interstate pipelines.[4]

Cases involving Canadian imports and "transportation-only" pipelines to serve the Northeast, currently pending before the DOE and FERC, are attempts to escape FERC's remedial powers over sales for resale. In Brooklyn Union Gas Company, *et al.*, ERA Docket Nos. 86-44-NG, *et al.*, and Iroquois Gas Transmission System, *et al.*, Docket Nos. CP89-634, *et al.*, DOE and FERC are considering approval of Canadian natural gas import authorizations by Northeastern local distribution companies (LDCs) and construction and operation of interstate pipeline facilities to transport this gas. In a previous project to import Canadian gas to Northeast LDCs, a joint venture called Boundary Gas was formed to import the gas for resale to the LDCs. Boundary's rates are subject to FERC regulation. In response to Opinion No. 256, the LDCs have decided to rely upon a new entity called Alberta Northeast, which will take title to the Iroquois LDC's gas on the Canadian side of the border and export it to the individual Iroquois shippers. By restructuring the transaction so as to avoid a jurisdictional sale for resale within the United States, the applicants hope to avoid fair and equal treatment for Canadian and domestic costs and to take advantage of the difference in rate design methodologies used in Canada and the United States. The key to this "transportation-only" scheme is that if the sale for resale occurs in Canada it is regulated by DOE and it it occurs in the United States it is regulated by FERC and comes within the express terms of the principles outlined in Opinion No. 256. The above-cited cases are simply examples of many similarly structured import projects.

More importantly, to our knowledge no U.S. pipeline owns any pipeline facility in Canada. Just as interesting is the lack of significant U.S. natural gas exports to Canadian markets. In 1989, the U.S. imported 1,378 Bcf of gas from Canada and exported only 70 Bcf to Canada.[5] This is especially disturbing when most of our domestic natural gas is closer to Canada's markets than Alberta. These facts are not accidents but rather reflect a systematic denial of marketing opportunities in Canada. The U.S. Government is probably more to blame than the Canadian Government because one reason there is so little U.S. natural gas exported to Canada is that FERC-imposed rate design methodologies make it impossible for domestic pipelines to compete against TransCanada for those markets.

A. The northeast "settlement" process

The above-cited cases, NIPS and Iroquois, arose out of the Northeast U.S. Pipeline Projects proceedings in Docket Nos. CP87-451, *et al.* The difference in rate design methodologies, the way these projects are structured, and the configuration of their ownership are all reasons why the newest Northeast projects are primarily Canadian-supplied. TransCanada owns 29 percent of Iroquois Gas Transmission System. It is interesting and disturbing to note that TransCanada is one of the biggest owners of domestic U.S. interstate pipeline facilities and *always* owns substantial equity in any Canadian-U.S. gas supplied projects. TransCanada controls both the upstream Canadian facilities and the downstream U.S. facilities. During the "settlement" process, many domestically-supplied projects were scrapped and their sponsors were offered an equity position in Iroquois in return. Thus, most of the original sponsors of Iroquois had to accept reductions in their ownership interest. The only party never to have its equity position diluted was TransCanada. Although the contested settlement contemplated hearings in the individual certificate proceedings, and

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[4] *See e.g., Natural Gas Pipeline Company of America,* 37 FERC 61,215 (1986) (Opinion No. 256), rehearing granted in part and denied in part, 39 FERC 61,218 (1987) (Opinion No. 256-A), aff'd sub nom. *TransCanada Pipelines Limited* v. *FERC,* 878 F.2d 401 (D.C. Cir. 1989) and *Pacific Gas Transmission Company,* 50 FERC 61,067 (1990).

[5] EIA, Monthly Energy Review, Dec. 1989, p. 67.

IPAA has repeatedly asked for such hearings, FERC has yet to schedule a single evidentiary hearing for the Northeast projects.

B. The most recent developments

On April 11, 1990, FERC considered and approved in principle the construction and operation of interstate pipeline facilities designed to transport Canadian gas to Northeastern markets in Tennessee Gas Pipeline Company, Docket Nos. CP88–171, *et al.* (Also known as the Niagara Import Point Settlement, or NIPS, Phase II). Although the volumes at issue are relatively small in this phase, only about 107 MMcf/d, the FERC saw the issue in generic terms and acted as though its handling of NIPS would be treated as precedent for future "transportation-only" pipelines carrying Canadian gas.[6] In its April 11, 1990 vote in principle the FERC concluded that "because there are no sales for resale being made by the pipeline applicants . . . the concerns addressed in Opinion No. 256 are not present in this proceeding." [7] In other words, the Commission accepted the view that the NIPS procedure for transporting Canadian gas is either not a problem or, if it is a problem, FERC can do nothing about it. From the discussion it hard to tell just exactly *why* FERC feels that the NIPS case is not an appropriate proceeding in which to decide whether there is discrimination against domestic gas. Chairman Allday indicated in his April 11 comments, that he felt constrained by law to dismiss IPAA's concerns because he "did not want to violate the Free Trade Agreement." However, in his April 24, 1990 letter to Senator Phil Gramm on the subject of discriminatory rate structures for Canadian gas, Allday stated that "the matter is receiving thorough consideration by the Commission . . . in a number of . . . proceedings. . . . The Commission is committed to enabling Canadian and domestic producers to compete on a fair and nondiscriminatory basis." While the answer to Senator Gramm is laudable, it is completely inconsistent with the FERC Chairman's position stated on April 11 and it holds out nothing but false hope to domestic producers. I do not believe that either of these answers can withstand scrutiny.

1. The Free Trade Agreement.—The United States-Canada Free Trade Agreement (FTA) [8] in no way prevents the Commission from continuing it efforts to establish a "level playing field" for competition between domestic and Canadian supplies. The FTA expressly protects FERC's ability to prevent undue discrimination on those occasions where, as in Opinion No. 256, there is a sale for resale by an interstate pipeline. Opinion No. 256 addressed a competitive advantage conferred on imported gas as a result of the rate design used in Canada. During the course of considering implementing legislation for the FTA, members of Congress expressed concerns that the FTA might be used to limit or overturn the important principles of fair competition embodied in Opinion No. 256.

In its Statement of Administrative Actions, the message to Congress explaining how the Administration interpreted the Free Trade Agreement, the Administration first addressed these concerns:

> Implementation of the Agreement requires no changes in federal laws regulating natural gas or electricity including, among others, the Natural Gas Act (NGA), the Natural Gas Policy Act (NGPA), . . . Such laws are considered to be consistent with the Agreement in that none of their provisions has been identified as requiring actions contrary to the Agreement.[9]

The Statement continues by expressly discussing Opinion No. 256:

> FERC's recent decisions in Opinion No. 256 and Order No. 500 accord the requisite treatment to Canadian natural gas. FERC Opinion No. 256 is the so-called "as-billed" decision, on the "pass-through" of natural gas costs; it required a U.S. pipeline company to use the same rate design for Canadian and U.S. gas (and related costs). FERC Order No. 500 established a new "open access" transportation program; it established the rules under which U.S. pipelines may transport gas owned by others. Both Opinion 256 and Order 500 have been appealed to a federal court.
>
> FERC's action in each instance is consistent with the FTA. All natural gas supplies are treated alike regardless of nationality. Neither discriminates based on nationality, either against Canada or Canadian gas companies or in favor of U.S. gas

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[6] "Treatment of this case will set a precedent for other pending [Canadian] matters," said Commissioner Trabandt. "The significance of this order goes way beyond the [Niagara import] project," said Commissioner Moler. Commissioner Langdon said this case would "dictate how we're going to be dealing in the future with the Canadians."

[7] Discussion Draft of "Order Issuing Certificates" provided by FERC on April 11, 1990, subject to revision, at 31.

[8] H.R. Doc. No. 216, 100th Cong., 2d Sess. (1988), 27 I.L.M. 281.

[9] Statement of Administrative Actions at 55.

companies. Accordingly, the FTA does not require FERC to change either action, in any particular way, or not all. Nor does the FTA "lock-in" either action in the current form, or otherwise prevent FERC from revising it (or any other rule, opinion, or order) in the future.[10]

Thus, the clear intent was to endorse the fairness principles of Opinion No. 256 and not to limit them to merely the sales for resale context.

These views were carried forward from the Statement of Administrative Actions to the Congressional consideration of the implementing legislation. The Senate Energy Committee Report on the legislation noted an exchange of correspondence between Chairman Johnston and Canadian Ambassador Allan Gotlieb which specifically noted that Opinion No. 256 was not affected by the FTA.[11] The Report also endorsed the description of the effect of the Agreement on natural gas regulatory matters contained in the Statement of Administrative Action, as clarified by the Report.

Thus, it is painfully clear that FERC and DOE remain free to carry out the mandate under the Natural Gas Act to prevent undue discrimination against domestic gas. The FTA is not a barrier to this statutory duty.

2. Lack of objective analysis.—The second rationale for rejecting our concerns in the context of specific certificate applications, that such concerns are better dealt with elsewhere, is a continuation of the "shell game" to which I have already referred. *When* and where do we finally get a hearing? And, how many Canadian-supplied facilitites will be constructed in the meantime based on assumptions which have not been tested by expert testimony and cross examination? For example, a key element in assessing the "public convenience and necessity" of a pipeline construction project is determination of the marketability of the gas in the service area as well as a determination as to whether the netback prices at the wellhead will attract gas supplies to the project. Neither FERC nor DOE has performed an objective analysis of these crucial issues.

FERC launched its open-season proceeding prior to TransCanada's filing its facilities application before the NEB. The open-season proceeding considered the relative merits of projects to transport domestic gas to the Northeast along with several alternative projects for transporting Canadian gas. The contested settlement reached in the open-season proceeding permitted the parties to elect among the various projects, with each sponsor filing a new application for a resized facility based upon the resulting customer commitments. This entire process occurred in the winter of 1988-89, prior to firm facility cost data becoming available from TransCanada.

Subsequent events illustrate the fallacies of this approach. Six months later, on June 29, 1989, TransCanada PipeLines Ltd. applied for its facilities authorization estimating the cost at $1.2 billion.[12] Subsequently, on February 12, 1990, the TransCanada cost had escalated to $2.6 billion.[13] In addition, the Federal District Court in Canada, in an unprecedented action, has remanded the issue of whether the cost of the TransCanada expansion will be priced on a rolled-in basis (to be paid by both existing Canadian and new U.S. shippers) or incrementally borne by just the Northeast U.S. shippers.[14] Robert Reid, President of Iroquois, has been quoted in the trade press claiming that incremental pricing would add more than 40 cents per Mcf to Canadian transportation costs for Iroquois shippers. He was quoted as doubting whether the Northeast U.S. market "can stand a 40 cent hit." [15]

In sum, DOE has issued conditional import licenses and FERC has continued to process certificate applications to transport imported gas to the Northeast while denying the need for evidentiary hearings. DOE and FERC have taken these actions without knowing the cost of the Canadian facilities, or whether under an incremental cost structure on TransCanada, the project will be able to attract Canadian gas supplies or domestic markets. This rush to judgment can only harm domestic gas consumers as well as domestic producers and ultimately burden gas consumers in the Northeast with billions of dollars of uneconomic new construction.

FERC's recently adopted "our hands are tied" approach is inconsistent with certain actions contemplated in the NIPS proceeding. In the draft order (at pages 15-

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[10] Id. at 56.

[11] S. Rept. 100-504, 100th Cong., 2d Sess. at 60-64.

[12] Foster Natural Gas Report, July 20, 1989, page 22.

[13] Foster Natural Gas Report, March 8, 1990, page 2.

[14] In its original decision, the NEB refused to consider evidence that the $2.6 billion expansion should be priced incrementally to Iroquois. The Chairman of the NEB, Rolan Priddle, removed himself from the case, apparently because of a reportedly impermissible contact with an official of TransCanada a few days after the court remand.

[15] Foster Natural Gas Report, March 8, 1990, page 2.

20) FERC goes to great lengths to restructure Tennessee's proposed anticompetitive 100 percent demand charge rates. IPAA supports this change but we are constrained to point out that, contrary to a statement made by one of the FERC Commissioners at the April 11 meeting, the imposition of modified fixed-variable rate design on 30 miles of pipe does not make a 2300 mile trip under a fixed-variable rate design "nondiscriminatory on its face." In fact, it is a pathetic excuse for fair play and an evasion of the true magnitude of the issue.

If projects like NIPS and Iroquois can escape Commission scrutiny regarding the fairness of the overall rate impact from Alberta to the customer's city gate, what is to prevent Pacific Gas Transmission Company (PGT) and any other pipeline to which Opinion No. 256 currently applies from restructuring its transaction to mimic the NIPS/Iroquois approach? There is nothing to prevent it. Inded, importers have every incentive to mimic the "transportation-only" approach and avoid a fair rate structure. Thus, while Opinion No. 256 currently applies to at least some of the Canadian natural gas imported into the United States, there is every reason to expect that such transactions will be restructured to avoid the Opinion No. 256 treatment. There is also every reason to expect that all future import projects will follow the "transportation-only" method. The end result: Opinion No. 256 will become a dead letter.

V. CONCLUSION

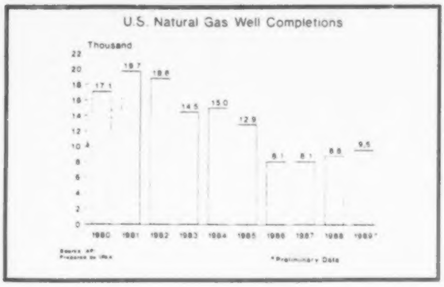
Domestic natural gas producers have sufficient supplies to meet the needs of consumers in the Northeast. These supplies are closer to the market and under an appropriate rate design, the facilities needed to carry domestic natural gas to Northeastern markets could be constuctured at a much lower cost than Canadian alternatives. Domestic producers are willing to make long-term commitments to this market, on terms not too dissimilar to those commitments signed by Canadian suppliers of Northeast projects, *provided* we enjoy the same pipeline transportation rate treatment enjoyed by the Canadians. Under similar pipeline rate design methodologies, domestic natural gas would be economically preferred in Northeast Markets. One problem is that FERC has forced domestic U.S. pipelines to operate under radically different conditions compared to those faced by Canadian pipelines. The other problem is that both FERC *and* DOE refuse to address this problem in the context of approving additional import authorizations and certificates. Only in the context of considering import licenses or certificates can this dscriminatory impact be addressed in any meaningful way. Mr. Chairman, domestic natural gas producers are not asking you or this Committee to fight our battles for us. We are only asking you to give us a forum for fighting our own battles. With the benefit of the traditional American system of due process we can establish a level playing field fo domestic and imported natural gas. Achieving this goal will bring producers and consumers on both sides of the border what all fair-minded people want—a realistic and fair North American gas market.

Thank you very much for giving me an opportunity to testify. I will be happy to answer any questions.

Exhibit 2.

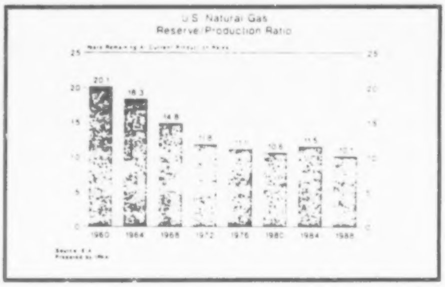
NATURAL GAS

U.S. Natural Gas Trends

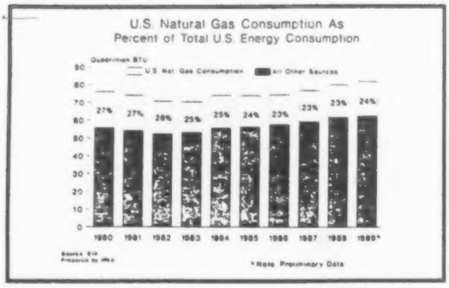

U.S. Natural Gas Well Completions

Source: API
Prepared by IPAA

*Preliminary Data

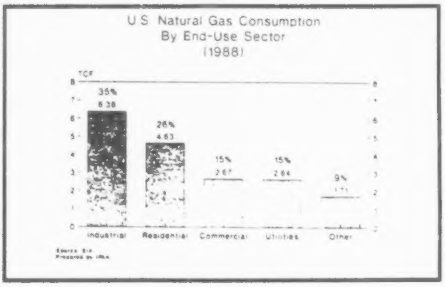

U.S. Natural Gas
Reserve/Production Ratio

Source: EIA
Prepared by IPAA

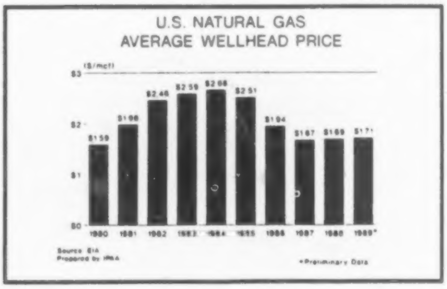

U.S. Natural Gas Consumption As
Percent of Total U.S. Energy Consumption

Source: EIA
Prepared by IPAA

*Note: Preliminary Data

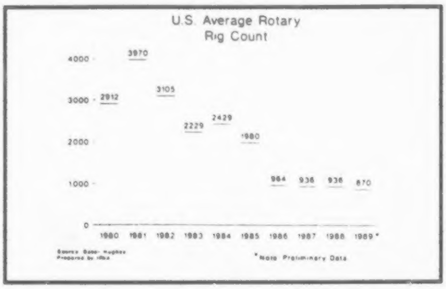

U.S. Natural Gas Consumption
By End-Use Sector
(1988)

Source: EIA
Prepared by IPAA


U.S. NATURAL GAS
AVERAGE WELLHEAD PRICE

Source: EIA
Prepared by IPAA

*Preliminary Data


U.S. Average Rotary
Rig Count

Source: Baker Hughes
Prepared by IPAA

*Note: Preliminary Data

Exhibit B

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

BROOKLYN UNION GAS COMPANY,et. al.)ERA DOCKET NO.86-44-NG,et. al.

U.S. AND CANADIAN PIPELINE RATEMAKING
ON BEHALF OF THE
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

May 1989

PRATHER ENERGY CONSULTANTS, INC.
ALEXANDRIA, VIRGINA

U.S. AND CANADIAN PIPELINE RATEMAKING ON BEHALF OF THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Introduction

Canada, primarily through the National Energy Board (NEB) and the U.S., through the Federal Energy Regulatory Commission (FERC or Commission) follow the principle of cost based ratemaking of their regulated natural gas pipelines.

The pipeline systems of the two countries are similar and neither appears to have an economic advantage over the other. Both systems were constructed during the same time period using state of the art equipment and construction techniques. This results in similar average costs per mile of haul of natural gas. Both countries have deregulated some or all of the producing segment of the natural gas industry and have been experiencing a temporary over supply which has lead to very competitive marketing by the producers.

The principle difference between the two end products is in the determination of cost responsibility by the two government agencies. The NEB follows actual cost behavior through the complete ratemaking process and as a result has a fixed variable rate design which does not burden the commodity rate with fixed costs. The Federal Power Commission (FPC) and FERC on the other hand, have always transferred a very substantial amount of fixed costs to the commodity. The Canadians collect approximately 20 percent of their costs through the commodity while the domestic pipelines collect up to 50 percent of their costs from the commodity. The difference being the artificial transfer of fixed costs to the commodity by the FERC.

The end result is that in a free-market environment where the well head prices of gas for a major market segment reflects the competitive fuel prices at the burner tip less the commodity charge for transportation. The Canadian producers have a distinct economic advantage over their counterpart in the United States in head-to-head competition for the same markets.

Background

The FPC, the predecessor to the FERC, developed the cost based approaches to pipeline ratemaking soon after the passage of the Natural Gas Act. It followed many of the approaches that had been developed under the Federal Power Act including the classification of costs between fixed and variable. The fixed variable approach is still used in the development of electric rates by the FERC.

The FPC followed the analytical approach utilizing four separate steps in its ratemaking process. In its early years (prior to adoption of the Seaboard method), the Commission utilized a cost classification method based on the behavior of cost, i. e., fixed-variable. The allocation method employed by the Commission at that time was based on what is commonly referred to as peak responsibility. Under the peak responsibility method, fixed costs were allocated on the basis of customer daily demand and variable costs were allocated on the basis of annual volumes. In the cases cited below, the Commission considered a portion of return and taxes fixed and a portion as variable. In the design of rates, classified costs were directly translated to jurisdictional rates except that an appropriate amount of fixed costs was assigned to interruptible jurisdictional service. The fixed-variable concept of cost classification was discussed in Opinion No. 73, Canadian River Gas Company et al., 3 FPC 32, 62 (1942):

> Commission staff exhibits on cost allocation followed principles that have long been recognized as reasonable in the public utility field and are widely accepted. Therein costs are divided essentially into two groups, fixed and variable. Fixed costs are largely joint costs which do not vary with volume of sales. The total amount of such costs are largely proportional to the maximum demand on the system or system capacity. Accordingly, these costs have been allocated basically in proportion to each customer's responsibility for the peak day demand. Variable costs are largely those that vary proportionally. to output or volume of sale. Accordingly, these costs have been allocated in proportion to volume of gas purchased by each customer.

The analytical justification for defining which costs are fixed and those that are variable was expressed in Opinion No. 91, Interstate Natural Gas Company, 3 FPC 416, 428 (1943).

> In general, the fixed costs are associated with demand and the variable costs with volume. An exception to this rule relates to return, Federal and state income taxes and Federal capital stock taxes. These, to the extent they related to transportation and delivery of gas, we allocate 50 percent to the demand and 50 percent to volume. The reason for this latter division is that a part of the return or profit should naturally come from part of the volume of business and a part from the customer's demand, that is, the capacity of facilities required to render service. Income taxes and capital stock taxes are associated with return and are, therefore, allocated in the same manner.

Later the Commission was concerned that off-peak customers might not be bearing an appropriate share of fixed costs. Such concern was expressed in Opinion No. 126, Mississippi River Corporation et al., 4 FPC 340 (1945) and later adopted as Commission policy by formulation of the Seaboard methodology in Opinion No. 225, Atlantic Seaboard Corporation, et al., 11 FPC 43 (1952) and Opinion No. 228, Northern Natural Gas Company, 11 FPC 123 (1952).

In Seaboard, the Commission departed from its prior practice of assigning fixed costs to the demand component of space rates. The Commission reasoned that a pipeline is not built solely to provide service during periods of peak demand; that service to customers who do not require service on peak days also enters into system design and pipeline construction decisions; and that the "interruptible" customer who takes gas on an annual basis, but is cut-off on the peak day, should also be assigned some of the fixed costs of the pipeline. The Commission concluded in Seaboard, II FPC at 56, "that the amount of fixed costs to be assigned to demand and commodity components of rates can be determined only by judgment because: The facts upon which the determination must be made are not susceptible to mathematical computation. We know that both functions are very significant. This is not a case where one form of joint use greatly predominates. It is our opinion that these significant cost factors should be weighted equally, that is to say 50% should be assigned to demand and 50% to commodity."

These shifts decreased the unit demand charge and increased the unit commodity charge. This has the effect of increasing the cost responsibility of the high load factor customer of the pipeline and decreases the cost to the low load factor customer. A customer that is using the system at the system-average load factor is unaffected by the Seaboard shifting of costs.

The Commission in Seaboard relied upon its arbitrary and unsupported judgment rather than basing its decision on analysis of each customers' responsibility for the capacity of the system and the related costs. Moreover, it attempted subsequently to apply Seaboard throughout the industry, regardless of the individual load characteristics of each pipeline and without any attempt to demonstrate the existence of industrial customers not paying their fair share of fixed costs. This change in philosophy has been carried forward and is reflected in the subsequently adopted United method and to a lesser extent in the Modified Fixed-Variable (MF-V) method, which will be discussed later.

Shortly after the Seaboard method was firmly established as Commission cost classification policy, modifications were required. A strict application of the Seaboard formula in rate proceedings before the Commission resulted in rates which effectively precluded industrial sales of natural gas because of competitive market conditions. As a result, the Commission used a ratemaking procedure commonly known as "tilting".

In this process, the Commission arbitrarily returned to the demand component a portion of the fixed costs assigned to the commodity component under Seaboard so as to produce a more competitive rate. First, a competitive price was determined. The appropriate amount of fixed costs was then transferred to demand to establish that predetermined price level.

Some of the principle cases in which the tilt was applied are Opinion No. 320, Midwestern Gas Transmission Company, 21 FPC 653 (1959); Opinion No. 379, Southern Natural Gas Company, 29 FPC 323 (1963); Natural Gas Pipeline Company of America, 28 FPC 731 (1962) and in Opinion No. 477, Midwestern Gas Transmission Company et al., 34 FPC 973 (1965).

. During the 1960's the Commission's staff experimented with a number of methods in an attempt to develop unit costs that could be directly translated into rates. In the 1970's this effort was abandoned in favor to the United method due, in part, to the shortage of gas supply that resulted in part from low well head pricing caused by the FPC rate regulation.

The United method of cost classification, cost allocation and rate design was first applied by the Commission in Opinion No. 671, United Gas Pipe Line Company, 50 FPC 1348 (1973) and was applied widely by the Commission until the mid 1980's when it adopted the MF-V method. The United method assigned the pipeline's transmission and storage fixed costs 75% to the commodity component of and 25% to the demand component. Production and gathering fixed costs were classified 100% to commodity. Transmission and compression by others, purchased gas costs, and contracted storage services were classified on an "as billed" basis.

Briefly the reasons the Commission gave for moving first to Seaboard and then to United are as follows:

In Seaboard, the Commission's rationale related to:

(i) The perceived need to assign more fixed costs to off-peak customers, particularly the direct industrial market;

(ii) The Commission's judgment that annual use should bear responsibility for fixed costs equal to peak usage.

With respect to United, the Commission was concerned about the causes, effects and possible solutions for the gas shortage. Specifically, the Commission mentioned the following factors:

(i) Worsening gas supply
(ii) Curtailments
(iii) Narrowing the gap from alternate fuel prices, and
(iv) Reducing the discount for large volume industrial users.

In Opinion No. 671, the Commission established the United method, relying not on analysis of cost behavior and responsibility, but on its judgment. Specifically, it noted that United was "midway between the Seaboard 50-50 ratio and the volumetric method." As previously explained the rolling together of the steps of ratemaking has led to results which are arbitrary and inappropriate. Moreover, each of the points mentioned by the Commission in support of United was theoretically invalid and were actually counter productive to the Commission's intent to use pipeline rates to lessen the impact of the gas shortage.

The present MF-V method which was adopted by the Commission in the mid 1980's still loads an inordinate amount of fixed costs into the commodity rates and provides the Canadian producers with an unfair advantage as will be demonstrated later in this report.

Natural Gas Pipeline Company of America's (Natural's) rate history closely follows the Commission's practices and provides a good case study.

Beginning in 1957 and continuing through the 1960's and early 1970's, Natural's approach was to establish the level of the commodity rate in light of competitive fuel costs and to recover the balance of costs through the demand charge. This method utilized by Natural was a principle example of the Seaboard "tilt." A straight Seaboard method was adopted by Natural in Docket No. RP 72-132 and was utilized during the rate periods of Docket Nos. RP 73-110 and RP 74-96. In Opinion No. 782, Natural Gas Pipeline Company of America, 56 FPC 2976 (1976), the Commission ordered Natural to apply the United formula on its system, reversing an initial Decision which had upheld application of the Seaboard method on Natural's system. The United method was first actually applied to Natural's system during the Docket No. RP 75-108 rate period commencing December 1, 1975 and used until 1982 when after substantial modifications of Natural's proposal in Docket No. RP 81-49 the Commission adoped the MF-V method.

On October 28, 1985, the Commission issued Order No. 436 which radically changed the way the natural gas industry operated. Simply, Order Nos. 436 and 500 permitted the producers to enter the end-use markets in direct competition to the merchant's function heretofore provided by the pipelines. It also, permits distinct end-use markets to shop for competitive fuels on a delivered price basis. This has and will continue to be affected by the Commission's rate design methodology since the well head price to the producers is now on a "net back" basis.

As an outgrowth of Order Nos. 436 and 500 there has developed a viable "spot-market" for natural gas. This new segment of the industry is directly affected by the Commission's ratemaking policies.

Ratemaking Principles

As a general proposition the ratemaking process should consider first the nature or behavior of costs, then how the costs are incurred and, finally, the responsibility for the costs.

There are four major steps in the normal ratemaking process once the overall cost of service has been determined. These steps are commonly accepted in the industry and are reflected in the requirements for Statements I, J and K in §154.63 of the Commission's Regulations. These steps are:

(i) Functionalizaton of costs
(ii) Classification of costs
(iii) Allocation of costs
(iv) Design of rates

Each step in the ratemaking process should be considered analytically and implemented separately. By contrast, in the MF-V, United and Seaboard methods applied by the Commission, the four steps have been rolled together, resulting in costs classified and allocated on the basis of arbitrary judgment. In the case of United and MF-V, and to a lesser degree under Seaboard, such arbitrary costing was directly translated into rates. Consequently, jurisdictional rates designed under these methods were clouded. A proper method should produce rates that properly distribute and assign costs and risk between the pipeline and its customers, perform the intended task and in addition generate the proper economic signals to both consumers and producers.

The first step, functionalization, is the assignment of costs to major functions. For pipelines the primary functions are: production and gathering, underground storage and transmission. The costs that cannot be directly assigned are allocated to those functions on the basis of the relationship to directly assignable costs, e.g., ad valorem taxes are assigned to functions on the same basis as depreciable gross plant.

Under the typical rate structure of the natural gas transmission industry, it is necessary to establish demand and commodity costs. The nature of the industry is such that fixed costs are directly related to customer demand for capacity and variable costs are associated with annual delivery and sale of gas. The proper method of classification should closely track the behavior of the components of the cost of service, which comprise the pipelines aggregate revenue requirement.

In the gas pipeline industry, costs are either relatively constant or they vary in relation to the level of sales. The costs that are relatively constant are essentially unavoidable. For example, after a certificate has been issued and pipeline facilities are installed, costs associated with such plant investment continue at a relatively constant level, irrespective of the level of through-put. Such costs are identified as fixed. In contrast, the costs which vary closely with output will be incurred or avoided as a direct function of the level of through-put. These costs are identified as variable. Compressor fuel is an example of a variable cost.

The cost associated with the amount of service that can be provided is fixed and unavoidable for a particular level of plant investment and the corresponding level of service available. In the case of an interstate pipeline, much of its fixed costs are associated with facilities and the related operation and maintenance essential to provide the level of service it is obligated to provide under its certificate authorization and contracts. If rational results are to be obtained in the ratemaking procedure, it is essential that the behavior of the elements of the cost be accurately identified and reflected in cost classification. Otherwise, a classification of a cost which does not follow its behavior will result in a misassignment of the responsibility for such cost. By analogy, in the functionalization of costs it would be wrong to assign the cost of gas to the transmission function because a customer that is only having his gas transported would be assessed costs for a service not being received. Similarly, when fixed costs that are related to the level of service available are arbitrarily classified to the commodity component, revenues are recovered based upon the amount of service actually provided rather than on the basis of the service obligation to which such a fixed cost properly relates.

One of the most serious flaws in the Commission's MF-V method that has been carried forward from the Seaboard method is that it does not consider production and gathering costs in light of their cost behavior. The classification of such costs has no bearing on how those costs behave. For example, ad valorem taxes are fixed if they are unavoidable, not if they are assessed on facilities used to purchase gas from a producer.

The third step, allocation, is the apportionment of the total cost of service between appropriate customer groups, e.g., between jurisdictional and nonjurisdictional customer groups on the basis of their responsibility for such costs. Only a relatively small percentage of sales on the systems serving the east coast are to nonjurisdictional customers. Therefore, the allocation between jurisdictional and nonjurisdictional services has little impact on the ultimate jurisdictional cost of service and no detailed review of the allocation factors is appropriate for this analysis.

Once costs are classified between demand and commodity and allocated among customer groups, the resulting costs must be examined in the rate design step to determine if any modification is necessary to establish actual rates. Under the ideal proposal, the classification of jurisdictional cost of service between demand and commodity would be directly translated into the corresponding jurisdictional demand and commodity rates. Such a rate design is appropriate for the following reasons:

> (i) It provides an assurance of recovery of costs which are unavoidable. Such costs should not properly be placed at risk because their recovery is essential if the pipeline is to continue in business and meet its certificated service obligations.
>
> (ii) It represents a proper division of cost responsibility among customers by matching a customer's responsibility for costs with the level of service it can demand.

(iii) By aligning customers' cost responsibility with their right to capacity, such rate design provides the proper basis for the analysis by both the pipeline and its customers of whether new facilities should be constructed, whether they sould be built by the pipeline or by a pipeline's customers and the type of facilities which best meet the load characteristic of each customer e.g., pipeline, storage or peak-shaving facilities.

(iv) Customers can reduce unit costs substantially by improving their load factor. This enables them to manage their loads more effectively than under a method of rate design that loads fixed costs into the commodity.

(v) Finally, a proper rate design will provide the proper market signals to consumers since they will have the ability to accurately identify the commodity value of gas distinct from the fixed costs associated with the service rendered by the pipeline. Presumably, proper signals to the consumer will be translated back as proper market signals to the producer.

It is appropriate that customers bear costs in relation to their demands on the system. The installation of daily mainline transmission capacity results in a directly related amount of annual capacity. There is no justification for a customer who is utilizing its daily contract capacity at a very high load factor on an annual basis being required to subsidize a customer who is only using half of the annual capacity that is related to such customer's daily contracted capacity. Yet, that very result is obtained by application of a rate design which assigns responsibility for fixed capacity costs by pricing them in the commodity component of rates to be allocated over annual sales rather than peak day demand.

Under a method that shifts fixed costs to the commodity there is some opportunity for a distributor or an end-user to reduce its unit cost by an improvement in load factor. Practically, however, the amount of improvement under such a method is so small that investment in peak shaving facilities to improve the load factor of the purchaser from the pipeline may not be warranted. Thus, any load factor improvement can come about only by increased off-peak or interruptible sales. Increased sales may not be a viable alternative because competitive fuel prices may be lower than the minimum price required by the producer plus the heavily loaded commodity charges that result from an arbitrary method such as employed by the Commission.

The Modified Fixed-Variable Method

From a cost behavior and incurrence standpoint, the MF-V method is superior to the United method since some of the costs that are fixed and do not vary with through-put are reflected in the demand charges, however, the Commission's continuation of shifting large amounts of fixed costs to the commodity still results in serious problems within the industry. The MF-V method subjects all the return on common equity, the pure risk element in the company's cost of service, and all the fixed costs of production and gathering to a volume risk.

The Commission's rate design must fit in with gas deregulation. Since the mid-1950's, natural gas has been subject to regulation at a price well below that of alternative fuels. Contracts between producers and pipelines have thus generally provided for prices at the highest levels allowed by the Commission. As the industry has moved into deregulation, the same contract pricing guidelines have not been available. A very substantial spot market has developed replacing in large part the long-term contracts between pipelines and producers. Producers, consumers and pipelines are negotiating price levels and other terms consistent with the market value of gas in competition with alternative fuels. As a result, it is critical that the correct "market signals" be available at the bargaining table. Rates that identify costs accurately are an essential element of this process. The producers must be in a position to recover the actual commodity value of gas from the market. The consumer, not the pipeline, is in a position to evaluate end-user price. Commodity value should not be prejudged by the pipeline rates that do not reflect the proper transportation costs. However, if the commodity component of rates is improperly burdened with fixed costs, as it is under the MF-V rate design, the producer is at a disadvantage when it tries to reflect the commodity value of gas in its negotiations and is placed at a competitive disadvantage vis-a-vis other fuels and Canadian suppliers. Under these circumstances, neither end user nor producer gets the correct pricing signals.

The analysis of the proper pipeline rate design begins by examining the cost of service to establish categories of costs for determining whether they are fixed or variable in nature. The basic categories of a pipeline's cost of service for its gas sales and transportation can be divided into four general categories: (i) the cost of gas, (ii) operation and maintenance expenses, (iii) taxes and (iv) capital or investment-related costs.

In the past, it has been generally assumed that the cost of gas varies with the annual sales, and therefore, should be classified to the commodity component. The errors in this approach are discussed in detail later in this study. For now a simple statement that some of a company's gas costs do not vary with volume, or that those which vary with volume do not follow a straight-line relationship is provided. As an example, to the extent that a company's gas purchase contracts contain take-or-pay provisions, that company would have a fixed cost associated with that contract. It has been known for some time that this fact exists, but Commission treatment of this cost phenomenon has not materially changed over the years. Now is the time for the Commission to review this subject.

Some of the operation and maintenance expenses vary with volume and others do not. For example, fuel and power for compressor stations and fuel and power for purification equipment are considered to be a function of the volumes and are therefore classified as variable. On the other side, there is no way from a practical standpoint that a company can adjust its labor expenses for changes in through-put during a period when particular rates are in effect. Therefore, labor costs are considered as a fixed item. Besides labor and fuel, the remaining O&M items consist primarily of materials and supplies and services performed by somebody other than the company. The materials and supplies do not really vary with sales volumes. The outside services, such as transportation of gas by others, are provided by contract, and therefore, classification follows the contract terms, i.e., "as billed". There can be other minor items in this category, but they are insignificant. Only a small amount of other taxes are considered to be variable in nature and therefore are classified to the commodity component. The remaining other taxes and income taxes are part of the category designated as capital or investment-related costs.

A principal attribute of the Commission's MF-V classification method is that it matches the way some of the test period costs are determined with the way such costs are incurred in the period that the rates are in effect. The capital or investment-related costs under consideration consist of depreciation, remaining other taxes, return and income taxes. Taking each of the capital cost items separately, and in the reverse order, will show what is meant.

In a rate increase filing income taxes are a result of, and mathematically related to, the return on equity. This is also true in an actual period where the income taxes are a function of the return on equity or net income.

Return consists of three components: a debt component, a preferred component, and an equity component. The long-term debt component of return for the test period has its counterpart in interest that must be paid from revenues in the actual period. Likewise, the preferred component has its counterpart in the actual period which is the preferred stock dividends. The third component of return, the return on equity, has its counterpart in the actual period, i.e., net income. Thus, return on equity is, in effect, a residual that accrues to the stockholders after the payment of all other fixed and variable costs of the pipeline.

Ad valorem taxes are typically calculated on the basis of the value of the plant in a particular locality. Social security payments are a function of labor. Franchise and license fees are set by each locality and are generally specified amounts. Since these taxes do not vary with output they are therefore classified as fixed.

The last capital or investment-related cost is depreciation and it can be either fixed or variable depending on how it is determined and how it is carried on the financial statements of a company. Straight-line depreciation, in effect, charges a fixed amount per unit of time -- either month or year -- while the service output method of depreciation charges a given amount per unit of service. In the first case, depreciation is a fixed charge for both the test period and the actual period. In the second case, depreciation is a variable charge. In most cases, depreciation is booked on a straight-line basis as a percent of gross plant and is therefore fixed with respect to cost behavior.

Under the MF-V classification methodology, the demand component contains a portion of the costs which are fixed and unavoidable for the period that the proposed rates will be in effect. The commodity component contains the fixed costs not included in the demand plus the avoidable or variable costs.

The Commission's MF-V method of pipelines ratemaking has four areas where serious flaws are evidenced, they are:

(i) Production and gathering costs are not classified in accordance with the behavior of such costs;

(ii) Gas costs associated with purchases from producers are classified as commodity;

(iii) The full equity return and associated income taxes are classified to the commodity; and

(iv) Interruptible sales and transporation rates are arbitrarily designed at the I00 percent load factor cost for firm service.

Production and Gathering Costs

As a matter of history, the Commission's classification of production costs to commodity was a subject of Northern Natural Gas Company, Opinion No. 228, II FPC I23, I37 (I952). In this Opinion, the Commission stated that, "It is the uniform practice in the industry to purchase gas in the field on a straight commodity basis. There appears to be no justification for a difference in treatments of the costs related to purchased or produced gas." It is interesting to note that the Commission's rationale in the Northern Opinion related to gas only and not facilities.

The Northern practice was generally followed for about I0 years until the Commission, in Southern Natural Gas Company, Opinion No. 379, 29 FPC 323, 342 (I963), stated, "Our consideration of this and other cases in terms of current economic factors leads us to believe that a classification different from that determined in Atlantic Seaboard and Northern Natural might be appropriate." Southern Natural proposed to classify at least 25 percent of its purchased gas costs to demand and fixed production costs other than purchased gas costs, one-half to demand and one-half to commodity in order to meet competitive fuel prices. The Commission's concern as expressed in Southern Natural started the FPC Staff on an evaluation of alternative cost classification and allocation procedures. There were three methods tested during the late I960's to develop a pricing method more in tune with the then-current economic conditions. These methods were identified as the Actual Use Method, the Relative Use Method and the Modified Seaboard Method. Each of these three methods classified some element of fixed production and gathering costs to demand. The Modified Seaboard Method was approved by the Commission in El Paso Natural Gas Company, Opinion No. 600, 46 FPC, 454 (I97I), at about the time the operations of the gas industry were going from a market-controlled to a supply-controlled situation. While the Modified Seaboard Method was short-lived, it provided that some fixed production and gathering costs should be classified to demand. The important point is that during a time when the market conditions were very much like today, there was a substantial effort to review the costing practices. It was not generally accepted that all production function costs are classified to commodity.

There is no justification for arbitrarily treating a pipeline's production and gathering costs in a manner other than on the basis of cost behavior. Some may argue that such costs are related to non-jurisdictional facilities and that the pipeline should be placed at risk for their cost recovery. If this is a serious concern and not a ploy to benefit low load factor customers, the Commission has the responsibility to determine the used and usefulness of any of the facilities that make up a pipeline's cost of service. Aside from the concerns of the Commission's authority and responsibility such misclassification results in serious problems with determining cost responsibility and places the domestic producers at a competitive disadvantage with Canadian producers and other fuel suppliers. The actual production and gathering facilities are like the pipeline's transmission facilities, capital intensive, and are used in a manner similar to the transmission facilities. The cost behave the same regardless of which accounting category the facilities are placed. The Commission's own definition of gathering is unclear, in fact, it does not exist in the Uniform System of Accounts. The Uniform System of Accounts defines production, transmission and distribution systems and from the reading of those definitions one could conclude that anything not classified as either production or transmission that is in between these two is gathering.

Furthermore, the misclassification of gathering costs, which in the case of Tennessee Gas Pipeline Company amounts to over I0 percent of its fixed costs, unnecessarily burdens the pipeline's commodity rates which is detrimental to the well head prices that the producer may receive.

Purchased Gas Costs

The Commission has historically treated purchased gas costs as a commodity in the development of a pipeline's rates except when such costs are associated with a purchase from another pipeline. Pipeline purchases are flowed-through on the as-billed basis. Producer related gas costs like production and gathering costs do not behave strictly as a variable cost. It has long been recognized that the take-or-pay provision of most long-term gas supply contracts represent the same revenue assurance to the producer that the demand charge provides to the pipeline.

Until recently the need to properly address the cost behavior of purchases from producers has been ignored by the Commission. Now with the free-market competitive environment this issue can no longer be treated as business as usual. The Commission is struggling with the concept of a Gas Inventory Charge (GIC) which will result in the consumers bearing a fixed charge for the pipeline holding a gas inventory for the consumer. In addition, there has now developed, in the form of a spot market, a measure that could be used to separate the long-term contract prices of a producer contracts between demand and commodity. For example, a pipeline, that has both long-term and spot supplies, could use its average spot price as the measure of the variable costs of its long-term supplies and any long-term supply costs in excess of the spot would deamed to be fixed and thereby properly classified to demand. An alternative would be for the Commission to encourage the pipelines to reform their existing contracts and to form new long-term contracts on a demand-commodity basis.

Equity Return and Associated Income Taxes

The Commission's classification of fixed equity costs as commodity while theoretically sound has a major flaw in the way it has been allowed to be treated.

As a general observation the debt-equity ratio of the industry has thickened considerably as the original debt incurred when the major pipeline systems were constructed has been retired. Since the late 1960's substantially all of the major pipeline construction projects have been financed on a stand alone basis with several pipelines forming new companies, e.g.; Ozark, Trailblazer, etc. By and large the equity ratios have increased due to the retirement of debt and the accumulation of retained earnings. This is a very complicated subject that needs to be addressed in more detail than is available for this paper.

The problem being faced by the domestic producers, particularly with the MF-V method, is that costs are inappropriately being loaded into the commodity rates which aggravates the competitive situation with Canadian producers. The following example illustrates the impact on the thickening of the equity vis-a-vis the MF-V method:

Impact of Debt Equity Ratio

Line No.	Description a	Ratio b	Cost c	Weighted Cost d	Income Taxes [1] e	Adjusted Weighted Cost f	Percent Fixed to Commodity g
1	Debt	75.00%	10.00%	7.50%		7.50%	
2	Equity	25.00%	15.00%	3.75%	1.93%	5.68%	43.10%
3	Total	100.00%		11.25%		3.18%	
4	Debt	50.00%	10.00%	5.00%	5.00%		
5	Equity	50.00%	15.00%	7.50%	3.86%	11.36%	69.44%
6	Total	100.00%		12.50%		16.36%	
7	Debt	25.00%	10.00%	2.50%		2.50%	
8	Equity	75.00%	15.00%	11.25%	5.80%	17.05%	87.21%
9	Total	100.00%		13.75%		19.55%	

Notes: [1] At 34% Tax Rate

This illustration shows that with all other components remaining the same, as equity thickens the total costs increase and there is a substantial increase in the fixed costs in the commodity.

It's interesting to note that the intent of placing the equity return and income taxes in the commodity was to place some risk on the pipelines. If the frequency of the pipelines filing major rate increase applications can be used as a gauge it would appear that the pipelines have not suffered from this preconceived risk.

Interruptible Rates

The Commission's policy of requiring that the maximum interruptible transportation rates be based on "fully allocated" costs is inappropriate from a theoretical standpoint, may not result in the lowest reasonable rates for other classes of service, and is detrimental to the competitive situation between domestic and Canadian producers.

The term "fully allocated" costs has come to mean that interruptible transporation rates will be based on the average cost of the comparable firm transporation rates at l00 percent load factor. This useage of the term is inappropriate since the interruptible service may not need the same cost functions as firm service. For example a pipeline system that augments its transmission capacity at the time of system peak by the use of storage may have storage costs allocated to the firm transportation service. However, the interruptible customer would be curtailed on the day of peak firm demand and, therefore, could not make use of the storage facilities. This results in the interruptible rate having unwarranted costs included in its design.

A serious point that the l00 percent rate design ignores is the fact that the interruptible customer has no rights to the peak day capacity of the system and in all liklihood will be curtailed during peak periods. This normally results in such a customer's actual use of the system being substantially higher than l00 percent. If costs are properly allocated on the basis of contract rights the interruptible customer would have no responsibility for those costs associated with the daily demand (D-l or R-l).

As a maximum the interruptible rate should be based on the allocated portion of the annual demand (D-2 or R-2) and commodity costs. Even this rate design may be excessive if it results in limiting competition that could be met with a lower interruptible transporation rate. It is an axiom of rate design that any rate that recovers its incremental costs and contributes something to the fixed costs is beneficial to the other customers using the system. The Commission's practices in this regard like those previously discussed are detrimental to the competitive situation of domestic producers when faced with the Canadian ratemaking concept.

Analysis of U.S. and Canadian Pipelines Rates

In order to demonstrate the severity of the problem four pipeline systems have been reviewed, two U.S. pipelines and two Canadian. These reviews for each pipeline system are presented in the four schedules contained in Exhibit No. I and were developed from the public documents listed below:

Schedule A
Tennessee Gas Pipeline Company, (Tennessee) -
Docket No. RP88-228
Schedule B
Texas Eastern Transmission Corporation (Tetco) -
Docket No. RP 88-67
Schedule C
NOVA Corporation of Alberta (NOVA) -
Customer letter of November 7, 1988
Schedule D
TransCanada Pipelines Limited (TransCanada) -
RH-I-88

The four sets of data are all of a comparable time period and reflect each company's proposal. Basically the studies start with the individual company's functional cost of service classified between fixed and variable and broken down by major cost components. The purchased gas costs were removed from the overall costs to service to obtain comparable cost of services for transportation. The costs were then tracked through the classification to demand and commodity, to the rate design and to revenue recovery for each of the companies studied. In order to compare the advantage that Canadian producers have over domestic producers the fixed and variable and the demand and commodity percentages of the total costs were determined for each system.

In summary these analyses demonstrate that cost patterns, i.e. fixed-variable relationships, are very comparable, as would be expected. The fixed costs represent a very high percentage of the total costs 85 percent for Tennessee; 73 percent for Tetco; 97 percent for NOVA; and 88 percent for TransCanada. NOVA's high percentage is probably due to the differences in the treatment of fuel costs.

The problem surfaces when a comparison is made of the percentage of costs included in the commodity. At this point the Canadians have a substantial advantage since their rate design is on a fixed-variable basis with the only shift of fixed costs into the commodity revenues associated with the interruptible services being provided under a straight line commodity rate. Such Canadian commodity rates are not priced at the 100 percent load factor charge of the firm services but rather on the basis of allocated cost responsibility. For example, the NOVA interruptible rates contain 7.7 percent of the fixed costs but the service represents 8.8 percent of the annual volume.

The following table summarizes the cost relationship among the four companies studied:

	Variable Costs	Commodity Costs
Tennessee	15%	50%
Tetco	27%	42%
NOVA	3%	10%
TransCanada	12%	21%

Impact Of Fixed-Variable Rates on Northeast Market

In evaluating who should supply incremental gas to the Northeast markets the question of the competing pipeline system's commodity charge is crucial. If we assume that the incremental facilities on existing pipelines that would be needed from either source (Canadian or domestic) would cost the same--due to distances the U.S. facilities should have an advantage--the evaluation should center on how the competing facilities would be utilized.

It can be easily demonstrated from economics and from past experiences that when two pipelines are serving the same market area that the swing or off-peak cut back is on the pipeline with the higher commodity charge. There is no known market area that is of such a nature that both systems could operate at 100 percent load factor, therefore, some swing would be inevitable.

The simple example (Exhibit No. 2) compairs two identical pipelines, Pipeline A, a Canadian system, with Fixed-Variable rate design and Pipeline B, a Domestic system, with MF-V rate design. These two systems are assumed to be serving a total market with a peak day demand of 7,000 M Dth per day with an annual load factor of 75 percent (1,916,250 M Dth). If the annual load were split equally between the two pipelines the unit cost would be as follows:

	Pipeline Company	
	A-Canadian	B-Domestic
Average Unit Cost, $/ Dth	$0.731	$0.731
D-1 charge, $/ Dthd/ Mo	$15.00	$6.02
D-2 charge, $/ Dth / Mo	N/A	$0.264
Commodity charge, $/ Dth	$0.073	$0.203
100% Load Factor charge, $/ Dth	$0.566	$0.566

However, with such a difference in the Commodity charges ($0.13/Dth) between the two pipeline systems, a prudent LDC would cut back on the Domestic system on any day when the market demand falls below the total capacity of the two systems. The result is that the Canadian system would operate at or near a 100 percent load factor and the cut back would be on the Domestic system. The resulting rates would be as follows:

	Pipeline Company	
	A-Canadian	B-Domestic
Average Unit Cost, $/ Dth	$0.548	$1.096
D-1 charge, $/ Dthd/ Mo	$15.00	$6.02
D-2 charge, $/ Dth / Mo	N/A	$0.396
Commodity charge, $/ Dth	$0.055	$0.305
100% Load Factor charge, $/ Dth	$0.548	$0.799

This disparage in rate making methods shifts the advantage to the Canadian system which if permitted to enter the Northeast market will have an adverse impact on domestic markets not connected to the Canadian system and on the domestic producers serving the existing markets and those that could serve the incremental markets. Initially the impact may not be critical but as peak-day markets develop the Canadian system would be able to unreasonably compete with alternate peak facility (e.g. underground storage) by being able to capture additional domestic supplied off-peak markets to maintain its high load factor and low average cost. As incremental load develops in this market area Canadian supplies will have the competitive advantage. This will result that with each expansion a larger share of the existing market will be lost to the unreasonable competition.

Conclusion

This analysis has demonstrated that there is a substantial difference in the pipeline rate structures between those used by the NEB and by the FERC. The Commission's attempt to develop a level playing field in Natural Gas Pipeline Company of America, Opinion No. 256, 37 FERC ¶61.215 (1986) has been unsuccessful. The Canadian's have not changed their procedures to match the flawed approach used by the FERC.

If the present MF-V method is continued by the FERC, it will provide Canada with an economic advantage in the Department of Energy's (DOE's) determination of whether the National interest is best served with new supplies from Canada for the Northeast. The initial unfair advantage may result in the Northeast being forced to depend upon its future supplies from Canada since the Canadian producers have a definite advantage over domestic producers and once facilities are in place they can not be easily supplanted.

Brooklyn Union Gas Company, et. al.
Review of Tennessee Gas Pipeline Company Rates
($,000)

ERA Docket Nos. 86-44-NG, et. al.
Exhibit No. 1
Schedule A
Page 1 of 2

Line No.	Description a	Total System Total b	 Fixed c	 Variable d	Production Total e	 Fixed f	 Variable g	Storage Total h	 Fixed i	 Variable j	Total Transmission Total k	 Fixed l	 Variable m
	Operating Expenses												
1	Prod. & Gath. Expenses	$1,666	$1,369	$297	$1,666	$1,369	$297	$0	$0	$0	$0	$0	$0
2	Expo. & Dev. Expenses	83	$83	$0	83	83		0			0		
3	Other Gas Supply Expenses	1,318,694	$10,104	$1,308,590	1,318,694	10,104	1,308,590	0			0		
4	Storage Expenses	38,235	$34,630	$3,605	0			38,235	34,630	3,605	0		
5	Transmission Expenses	259,563	$114,691	$144,871	0			0			259,563	114,691	144,871
6	A & G Expenses	116,459	$116,459	$0	2,991	2,991		2,615	2,615		110,852	110,852	
7	Total Operating Expenses	1,732,899	277,335	1,455,364	1,321,434	14,547	1,306,887	40,850	37,245	3,605	370,415	225,544	144,871
8	D, D & A Expenses	139,971	$139,971	$0	6,419	6,419		943	943		132,609	132,609	
	Taxes												
9	Federal Income	59,253	$59,253	$0	14,525	14,525		5,771	5,771		38,956	38,956	
10	State Income	8,855	$8,855	$0	1,629	1,629		647	647		6,578	6,578	
11	Other	55,117	$55,117	$0	242	242		973	973		53,902	53,902	
	Return												
12	Debt	55,875	$55,875	$0	13,305	13,305		5,287	5,287		37,283	37,283	
13	Equity	118,407	$118,407	$0	26,196	26,196		11,203	11,203		79,008	79,008	
14	Total Cost of Service	2,170,177	714,813	1,455,364	1,385,751	78,863	1,306,887	65,675	62,070	3,605	718,751	573,880	144,871
15	Credits	(55,329)	($23,642)	($31,688)	(23,902)		(23,902)	0			(31,427)	(23,642)	(7,785)
16	Total Cost of Service	$2,114,847	$691,171	$1,423,676	$1,361,848	$78,863	$1,282,985	$65,675	$62,070	$3,605	$687,324	$550,238	$137,086
17	Other Gas Supply Expenses	(1,313,672)	(7,081)	(1,306,590)	(1,313,672)	(7,081)	(1,306,590)						
18	Total C of S-X Gas Costs	$801,176	$684,090	$117,086	$48,177	$71,782	($23,605)	$65,675	$62,070	$3,605	$687,324	$550,238	$137,086
19	Percent of Total	100.00%	85.39%	14.61%	100.00%	149.00%	-49.00%	100.00%	94.51%	5.49%	100.00%	80.06%	19.94%

Line No.	Description	Total b	Demand c	Commodity d	Total e	Demand f	Commodity g	Total h	Demand i	Commodity j	Total k	Demand l	Commodity m
20	Total Operating Expenses	$419,027	$262,788	$156,239	$7,763		$7,763	$40,850	$37,245	$3,605	$370,415	$225,544	$144,871
21	D, D & A Expenses	139,971	133,552	6,419	6,419		6,419	943	943		132,609	132,609	
	Taxes												
22	Federal Income	59,253	0	59,253	14,525		14,525	5,771		5,771	38,956		38,956
23	State Income	8,855	0	8,855	1,629		1,629	647		647	6,578		6,578
24	Other	55,117	54,875	242	242		242	973	973		53,902	53,902	
	Return												
25	Debt	55,875	42,569	13,305	13,305		13,305	5,287	5,287		37,283	37,283	
26	Equity	118,407	0	118,407	26,196		26,196	11,203		11,203	79,008		79,008
27	Credits	(55,335)	(23,648)	(31,688)	(23,902)		(23,902)	0	0	0	(31,433)	(23,648)	(7,785)
28	Total C of S-X Gas Costs	$801,170	$470,138	$331,032	$48,177	$0	$48,177	$65,675	$44,448	$21,227	$687,316	$425,690	$261,626
29	Percent of Total	100.00%	58.68%	41.32%	100.00%	0.00%	100.00%	100.00%	67.68%	32.32%	100.00%	61.93%	38.07%

Source: FERC Docket No. RP88-228

ERA Docket Nos. 88-44-NG, et. al.
Exhibit No. 1
Schedule A
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Brooklyn Union Gas Company, et. al.
Review of Tennessee Gas Pipeline Company Rates
($,000)

Line No.	Description a	Total b	Demand c	Commodity d	Gas e	Grand Total f
	Supply IT Costs					
1	Trans IT	$35,236	$0	$35,236	$0	$35,236
2	A & G IT	11,379		11,379		11,379
3	Subtotal	46,615	0	46,615	0	46,615
	Supply FT Costs					
4	Trans FT	12,610	10,241	2,370		12,610
5	A & G FT	7,254	7,254			7,254
6	Subtotal	19,865	17,495	2,370	0	19,865
7	Supply Fuel & Losses				1,323	1,323
8	Total Supply Transport	66,480	17,495	48,985	1,323	67,803
	Market IT Costs					
9	Trans IT	58,201		58,201		58,201
10	A & G IT	5,302		5,302		5,302
11	Storage	2,383		2,383		2,383
12	Subtotal	65,886	0	65,886	0	65,886
	Sales and Market Area FT					
13	A & G	53,486	53,486			53,486
14	X-A & G	387,004	248,805	138,199	1,171	388,175
15	System Storage	20,463	14,152	6,310	1,367	21,829
16	Production	52,125		52,125	1,309,085	1,361,210
17	858	96,904	37,208	59,696		96,904
18	Bear Creek	28,636		28,636		28,636
19	FT Fuel & Losses				726	726
20	Subtotal	638,618	353,651	284,967	1,312,349	1,950,967
21	Storage Service	21,246	20,091	1,155		21,246
22	FSSTE-SSTNE	8,946	8,946			8,946
23	Total Revenues	$801,176	$400,183	$400,993	$1,313,672	$2,114,847
24	Percent of Total	100.00%	49.95%	50.05%		

PRATHER ENERGY CONSULTANTS, INC.

Brooklyn Union Gas Company, et. al.
Review of Texas Eastern Transmission Corporation Rates
[$,000]

ERA Docket Nos. 86-44-NG, et. al.
Exhibit No. 1
Schedule 9
Page 1 of 2

Line No.	Description a	Total System Total b	 Fixed c	 Variable d	Production Total e	 Fixed f	 Variable g	Storage Total h	 Fixed i	 Variable j	Total Transmission Total k	 Fixed l	 Variable m
	Operating Expenses												
1	Prod & Gath Expenses	$438	$207	$231	$438	$207	$231	$0	$0	$0	$0	$0	$0
2	Products Extraction	5,881	1,272	4,609	5,881	1,272	4,609	0			0		
3	Expo & Dev. Expenses	278	278	0	278	278							
4	Purchased Gas Costs	1,738,840	120,081	1,618,758	1,738,840	120,081	1,618,758						
5	Other Gas Supply Expenses	(73,123)	2,529	(75,651)	(73,123)	2,529	(75,651)	0			0		
6	Storage Expenses	43,538	35,877	7,661	0			43,538	35,877	7,661	0		
7	Transmission Expenses	307,324	125,264	182,060	64,372	31,579	32,793	755	398	357	242,197	93,287	148,910
8	A & G Expenses	89,843	89,843	0	1,701	1,701		1,252	1,252		86,890	86,890	
9	Total Operating Expenses	2,113,020	375,351	1,737,669	1,738,388	157,647	1,580,741	45,545	37,527	8,018	329,087	180,177	148,910
10	Donations	1,344	1,344	0	28	28		15	15		1,302	1,302	
11	D, D & A Expenses	105,541	105,541	0	47	47		3,408	3,408		102,087	102,087	
	Taxes												
	State and Federal Income												
12	Perferred	284	284	0	1	1		16	16		267	267	
13	Equity	73,658	73,658	0	217	217		4,073	4,073		69,368	69,368	
14	Tax Adjustment	(4,620)	(4,620)	0	(19)	(19)		(179)	(179)		(4,422)	(4,422)	
15	Other	25,133	25,133	0	300	300		711	711		24,122	24,122	
	Return												
16	Debt	47,034	47,034	0	139	139		2,601	2,601		44,294	44,294	
17	Preferred	483	483	0	1	1		27	27		455	455	
18	Equity	125,356	125,356	0	370	370		6,932	6,932		118,054	118,054	
19	Total Cost of Service	2,487,233	749,564	1,737,669	1,739,472	158,731	1,580,741	63,149	55,131	8,018	684,612	535,702	148,910
20	Credits	(8,877)	0	(8,877)	(8,877)		(8,877)	0			0		
21	Total Cost of Service	$2,478,356	$749,564	$1,728,792	$1,730,595	$158,731	$1,571,864	$63,149	$55,131	$8,018	$684,612	$535,702	$148,910
22	Other Gas Supply Expenses	(1,614,371)	(120,081)	(1,494,290)	(1,614,371)	(120,081)	(1,494,290)						
23	Total C of S-X Gas Costs	$863,984	$629,483	$234,502	$116,224	$38,650	$77,574	$63,149	$55,131	$8,018	$684,612	$535,702	$148,910
24	Percent of Total	100.00%	72.86%	27.14%	100.00%	33.25%	66.75%	100.00%	87.30%	12.70%	100.00%	78.25%	21.75%
		Total b	Demand c	Commodity d	Total e	Demand f	Commodity g	Total h	Demand i	Commodity j	Total k	Demand l	Commodity m
25	Total Operating Expenses	$2,113,020	$369,365	$1,743,655	$1,738,388	$151,661	$1,586,727	$45,545	$37,527	$8,018	$329,087	$180,177	$148,910
26	Donations	1,344	1,316	28	28		28	15	15		1,302	1,302	
27	D, D & A Expenses	105,541	105,494	47	47		47	3,408	3,408		102,087	102,087	
	Taxes												
	State and Federal Income												
28	Perferred	284	0	284	1		1	16		16	267		267
29	Equity	73,658	0	73,658	217		217	4,073		4,073	69,368		69,368
30	Tax Adjustment	(4,620)	(4,601)	(19)	(19)		(19)	(179)	(179)		(4,422)	(4,422)	
31	Other	25,133	24,833	300	300		300	711	711		24,122	24,122	
	Return												
32	Debt	47,034	46,895	139	139		139	2,601	2,601		44,294	44,294	
33	Preferred	483	0	483	1		1	27		27	455		455
34	Equity	125,356	0	125,356	370		370	6,932		6,932	118,054		118,054
35	Total Cost of Service	2,487,233	543,303	1,943,930	1,739,472	151,661	1,587,812	63,149	44,084	19,065	684,612	347,559	337,053
36	Credits	(8,877)	0	(8,877)	(8,877)		(8,877)	0			0		
37	Total Cost of Service	$2,478,356	$543,303	$1,935,052	$1,730,595	$151,661	$1,578,934	$63,149	$44,084	$19,065	$684,612	$347,559	$337,053
38	Other Gas Supply Expenses	(1,614,371)	(120,081)	(1,494,290)	(1,614,371)	(120,081)	(1,494,290)						
39	Total C of S-X Gas Costs	$863,984	$423,222	$440,762	$116,224	$31,579	$84,644	$63,149	$44,084	$19,065	$684,612	$347,559	$337,053
40	Percent of Total	100.00%	48.98%	51.02%	100.00%	27.17%	72.83%	100.00%	69.81%	30.19%	100.00%	50.77%	49.23%

Source: FERC Application-Docket No RP88-67

Brooklyn Union Gas Company, et. al.
Review of Texas Eastern Transmission Corporation Rates
[$,000]

Docket No. CP 88-824-001,et al.
Exhibit No. 1
Schedule 8
Page 2 of 2

Line No.	Description a	Total b	Demand c	Commodity d	Gas e	Grand Total f
	Sales for Resale					
1	Zones A,B,C & D	$628,464	$399,562	$228,902	$1,350,131	$1,978,595
2	Winter Service	34,252	18,892	15,360	48,059	82,311
3	Total	662,716	418,454	244,262	1,398,190	2,060,906
	Storage					
4	SS	4,342	2,326	2,016	641	4,983
5	SS-2	42,379	25,450	16,929		42,379
6	SS-3	23,004	13,601	9,403		23,004
7	X-28	7,469	4,811	2,657	860	8,329
8	Total	77,194	46,188	31,005	1,501	78,695
	Transportation Services					
9	X-43	2,808		2,808	578	3,386
10	X-127	3,443	1,054	2,389		3,443
11	X-129&130	2,685	814	1,871		2,685
12	FTS	7,805	2,518	5,287		7,805
13	FTS-2	10,206	3,116	7,090		10,206
14	FT-1	0	0	0		0
15	IT-1	58,459		58,459		58,459
	Offshore	3,015		3,015		3,015
16	Total	88,421	7,502	80,919	578	89,000
	Adjustments					
	DDD	13,844	13,844			13,844
	Columbia	9,866	9,866			9,866
15	Total	23,710	23,710	0	0	23,710
16						
17	Total Revenues [1]	$852,051	$495,864	$356,187	$1,400,270	$2,252,321
18						
24	Percent of Total	100.00%	58.20%	41.80%		

Notes: [1] Motion Rates Filed August 31, 1988

PRATHER ENERGY CONSULTANTS, INC

Brooklyn Union Gas Company, et. al.
Review of NOVA Corporation of Alberta Rates
(Can$,000)

ERA Docket Nos. 86-44-NG, et. al.
Exhibit No. 1
Schedule C
Page 1 of 1

				Export Services										
				Total Export			Interruptible Service			Firm Service			
Line No.	Description a	Total System b	Intra - Provincial c	Total d	Firm d	Variable d	Total e	Firm f	Variable g	Total h	Fixed i	Variable j	Percent Fixed Costs Interr. k
1	Variable Costs	$6,804	$799	$6,005		$6,005	$463		$463	$5,542		$5,542	7.71%
2	Operating & Maintance	147,973	17,374	130,599	130,599		10,067	10,067		120,532	120,532		7.71%
3	Depreciation	69,705	8,184	61,521	61,521		4,742	4,742		56,779	56,779		7.71%
4	Municipal Taxes	28,920	3,396	25,524	25,524		1,968	1,968		23,556	23,556		7.71%
5	Income Taxes	30,403	3,570	26,833	26,833		2,068	2,068		24,765	24,765		7.71%
6	Return on Rate Base	172,748	20,283	152,465	152,465		11,753	11,753		140,712	140,712		7.71%
7	Sub-total	456,553	53,606	402,947	396,942	6,005	31,061	30,598	463	371,886	366,344	5,542	7.71%
8	Transporation by Others	55,580	0	55,580	48,143	7,437	4,284	3,711	573	51,296	44,432	6,864	7.71%
9	Total	$512,133	$53,606	$458,527	$445,085	$13,442	$35,345	$34,309	$1,036	$423,182	$410,776	$12,406	7.71%
10	Percent of Total			100.00%	97.07%	2.93%	100.00%	97.07%	2.93%	100.00%	97.07%	2.93%	

		BCF/Day	BCF	Percent of Annual Quantity
	Volumes	18.0		
11	Total Contract Demand Quantity		2,013.7	
	Export Receipt Volume (annual)		193.0	8.75%
12	Firm Service		2,206.7	
13	Interruptible Service			
14	Total			

		$/Mcf	¢/Mcf
	Rates	1.90	
15	Export Firm Service Demand Rate per Month (T-5)		0.62
16	Export Firm Service Commodity Rate (T-5)		18.31
17	Export Interruptible Rate (T-6)		

		Total Export			Interruptible Service		Firm Service		
		Total	Demand	Commodity	Total	Commodity	Total	Demand	Commodity
	Revenues								
18	Export Firm Service (T-5)	422,885	410,400	12,485			422,885	410,400	12,485
19	Export Interruptible Service (T-6)	35,338	0	35,338	35,338	35,338			
20	Total	$458,223	$410,400	$47,823	$35,338	$35,338	$422,885	$410,400	$12,485
21	Percent of Total	100.00%	89.56%	10.44%	100.00%	100.00%	100.00%	97.05%	2.95%

Source: Customer Letter Dated November 1, 1988

Brooklyn Union Gas Company, et. al.
Review of TransCanada PipeLines Limited Rates
[Can$,000]

ERA Docket Nos. 86-44-NG, et. al.
Exhibit No.1
Schedule D
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		Total System						
		Total	Total		Fixed		Variable Trans.	
Line No.	Description a	System b	Fixed c	Variable d	Metering e	Trans. f	General g	Misc. h
1	Transmission by Other	$223,782	$131,573	$92,209	$0	$131,573	$91,746	$463
2	Operation and Maintenance	158,821	140,830	17,991	43,056	97,774	17,991	
3	Depreciation	101,318	101,318		1,154	100,164		
4	Municipal amd Other Taxes	43,397	43,397		459	42,938		
5	Income Taxes	83,736	83,736		1,150	82,586		
6	Regulatory Deferrals & Amort.	29,563	29,563			29,563		
7	Foreign Exchange Losses	854	854			854		
8	Other Operating Income	(556)	(556)			(556)		
9	Return	327,778	327,778		4,502	323,276		
10	Total Cost of Service	968,692	858,492	110,200	50,321	808,171	109,737	463
11	Misecellaneous Revenues	(39,205)	(36,847)	(2,358)	(2,047)	(34,800)	(2,348)	(10)
12	Net Cost of Service	$929,488	$821,645	$107,842	$48,274	$773,372	$107,389	$453
13	Percent of Total	100.00%	88.40%	11.60%	5.19%	83.20%	11.55%	0.05%

Source: National Energy Board Tolls Application RH-1-88

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Line No.	Description a	Total b	Demand c	Commodity d
	Test of Proposed Tolls			
	Canadian Firm Service			
1	Saskatchewan Zone	$1,031	$985	$46
2	Manitoba Zone	31,630	29,406	2,225
3	Western Zone	13,912	12,589	1,323
4	Northern Zone	47,262	42,023	5,239
5	Eastern Zone	601,140	434,447	166,693
6	Total Canadian Firm Service	694,974	519,450	175,525
7	Percent of Total	100.00%	74.74%	25.26%
8	Transgas Transporation	5,944	5,580	364
9	Percent of Total	100.00%	93.87%	6.13%
	Export Firm Service			
10	Herbert to Emerson	5,292	4,988	304
11	Empress to Spruce	2,292	2,163	129
12	Empress to Emerson	120,879	113,098	7,781
13	Empress to Niagara Falls	69,260	60,040	9,220
14	Empress to Cornwall	12,105	11,297	808
15	Empress to Sabrevois	8,471	7,377	1,094
16	Empress to Philipsburg	10,284	9,585	699
17	Total Export Firm Service	228,583	208,548	20,035
18	Percent of Total	100.00%	91.24%	8.76%
19	Total Firm Service	$929,501	$733,578	$195,924
20	Percent of Total	100.00%	78.92%	21.08%

Brooklyn Union Gas Company, et. al.
Impact of Rate Design [$,000]

ERA Docket Nos. 86-44-NG, et. al.
Exhibit No. 2
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Line No.	Description a	Pipeline Company A Total b	 Fixed c	 Variable d	Pipeline Company B Total e	 Fixed f	 Variable g	Line No.
	Cost of Service							
1	Total Cost of Service	$700,000	$630,000	$70,000	$700,000	$630,000	$70,000	1
2	**Percent of Total**	100.00%	90.00%	10.00%	100.00%	90.00%	10.00%	2
	Classified Cost of Service	Total	Demand	Commodity	Total	Demand	Commodity	
3	Demand-1		$630,000			$252,729		3
4	Demand-2		N/A			252,729		4
5	Total Cost of Service	$700,000	$630,000	$70,000	$700,000	$505,458	$194,542	5
6	**Percent of Total**	100.00%	90.00%	10.00%	100.00%	72.21%	27.79%	6
	Rates	Average	Demand	Commodity	Average	Demands	Commodity	
	Equal Division of Market							
7	Billing Units, MDth		42,000	958,125		42,000	958,125	7
8	D-2 Billing Units, MDth		N/A			958,125		8
9	Average Unit Cost, $/Dth	$0.731			$0.731			9
10	D-1 Charge,$/Dthd/Mo		$15.00			$6.02		10
11	D-2 Charge,$/Dth/Mo			N/A		$0.264		11
12	Commodity Charge,$/Dth			$0.073			$0.203	12
13	100% L.F. Charge,$/Dth			$0.566			$0.566	13
	Division of Market by Price							
14	Billing Units, MDth		42,000	1,277,500		42,000	638,750	14
15	D-2 Billing Units, MDth		N/A			638,750		15
16	Average Unit Cost, $/Dth	$0.548			$1.096			16
17	D-1 Charge,$/Dthd/Mo		$15.00			$6.02		17
18	D-2 Charge,$/Dth/Mo			N/A		$0.396		18
19	Commodity Charge,$/Dth			$0.055			$0.305	19
20	100% L.F. Charge,$/Dth			$0.548			$0.799	20

Brooklyn Union Gas Company, et. al.
Impact of Rate Design [$,000]

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Line No.	Description	Pipeline Company A			Pipeline Company B			Line No.
	a	Total b	Fixed c	Variable d	Total e	Fixed f	Variable g	
	Cost of Service							
1	Transmission Expenses	$259,563	$184,691	$74,871	$259,563	$184,691	$74,871	1
2	A & G Expenses	110,852	110,852	0	110,852	110,852		2
3	Total Operating Expenses	370,415	295,544	74,871	370,415	295,544	74,871	3
4	D, D & A Expenses	132,609	132,609	0	132,609	132,609	0	4
5	Federal Income Taxes	38,956	38,956	0	38,956	38,956	0	5
6	State Income Taxes	6,578	6,578	0	6,578	6,578	0	6
7	Other Taxes	53,902	53,902	0	53,902	53,902	0	7
8	Debt Costs	37,283	37,283	0	37,283	37,283	0	8
9	Equity Return	79,008	79,008	0	79,008	79,008	0	9
10	Credits	(18,751)	(13,880)	(4,871)	(18,751)	(13,880)	(4,871)	10
	Total	$700,000	$630,000	$70,000	$700,000	$630,000	$70,000	
	Classified Cost of Service	Total	Demand	Commodity	Total	Demand	Commodity	
11	Total Operating Expenses	$370,415	$295,544	$74,871	$370,415	$295,544	$74,871	11
12	D, D & A Expenses	132,609	132,609	0	132,609	132,609	0	12
13	Federal Income Taxes	38,956	38,956	0	38,956	0	38,956	13
14	State Income Taxes	6,578	6,578	0	6,578	0	6,578	14
15	Other Taxes	53,902	53,902	0	53,902	53,902	0	15
16	Debt Costs	37,283	37,283	0	37,283	37,283	0	16
17	Equity Return	79,008	79,008	0	79,008	0	79,008	17
18	Credits	(18,751)	(13,880)	(4,871)	(18,751)	(13,880)	(4,871)	18
19	Total	$700,000	$630,000	$70,000	$700,000	$505,458	$194,542	19

QUALIFICATIONS
of
William Prather

William Prather received a B.S. degree in Petroleum Engineering in 1957 from the University of Tulsa. While at the University of Tulsa, he worked for Oklahoma Natural Gas Company in its customer service department. After graduation, from 1957-1960, he was employed by Texaco, Inc. at its Electra, Texas field office as a petroleum engineer. From 1960-1964, he was employed by the Federal Power Commission (FPC) [now the Federal Energy Regulatory Commission (FERC)] as a general engineer in its Bureau of Natural Gas where the primary duties involved the analysis of rate and tariff issues in pipeline certificate proceedings, such as LNG peak shaving plants for interstate pipelines. Upon leaving the Commission in 1964, he was employed by Tenneco, Inc. in its Planning Department in Houston, Texas where the primary duties related to planning of pipeline systems, market surveys and analyses; competitive project analyses; pipeline operating problems; and regulatory work involving FPC matters.

In 1967, he returned to Washington, D.C. to work on the FPC's Technical Staff analyzing gas supply issues in several major pipeline certificate and rate curtailment proceedings. During last two years with the Commission from 1969-1971, his responsibilities also included supervision of the preparation of testimony by the Commission's Technical Staff in administrative rate proceedings regarding gas balancing, cost classification and allocation, rate design, tariff and gas supply allocation issues. He helped develop the first purchase gas adjustment clause (PGA) which became a part of an interstate pipeline's tariff.

From 1971 through November 1985, he was employed as a natural gas utility consultant with H. Zinder & Associates and was a Director of the parent company. During the period as a natural gas consultant at H. Zinder & Associates, he worked for various pipeline, distribution, production, and industrial companies on allocation, rate, tariff, depreciation, certificate, curtailment, purchased gas, and gas supply matters. He resigned in late 1985 to establish Prather Energy Consultants, Inc.

The work he has done for the interstate natural gas pipelines includes analysis, advice, and/or testimony on matters involving curtailments, PGA clauses, pipeline facility planning, estimates of capital and operating costs, cost of service, income taxes, depreciation, inventory accounting, billing units, zoning, tariff, rate design, FERC accounting, certificate and rate policy, sales and transportation marketing strategies, financing, and new projects for gathering, transmission, underground storage, LNG importation and storage, SNG production, propane air peak shaving and salt cavern storage. He testified in the proceeding where the modified fixed-variable method of cost allocation was first adopted by the FERC as a modification of his proposal.

His work with natural gas distribution companies has also involved numerous natural gas issues, including gas supply procurement, pipeline allocation and rate design, marketing strategies, load balancing, peak shaving, methods of start up cost deferment, service rules under Order Nos. 436 and 500 local regulatory policies.

He has testified as an expert witness before the Federal Energy Regulatory Commission, the National Energy Board in Canada, the Electric and Gas Board in the Province of Quebec, Canada, and the Public Service Commission of Nevada on cost classification, cost allocation, rate design, tariff, and other rate matters. He is a registered professional engineer and is presently a member of the American Gas Association's Financial Associates.

1

AFFIDAVIT of WILLIAM PRATHER

STATE OF VIRGINIA:
County of Fairfax:

William Prather, being first duly sworn, deposes and says that he is an employee of Prather Energy Consultants, Inc., that the foregoing document was prepared by him or under his supervision and direction at the request of the Independent Petroleum Association of America, that he has examined the statements contained therein, and that all such statements contained therein are true and correct to the best of his knowledge, information and belief.

WILLIAM PRATHER

Subscribed and sworn before me this 3rd day of May, 1989.

JoAnne S. Padberg
NOTARY PUBLIC

My Commission expires March 16, 1991.

Exhibit C

C.G.Edge & Associates Inc.,
2056 Brant Street, Unit 6,
Burlington, Ontario, L7P 3A6,
Canada,
Tel. 416 335 5280,
Fax 416 336 3626.
25 March 1989.

Mr Mark K Seifert,
Senior Counsel, Energy Regulation,
Independent Petroleum Association of America,
1101 16th Street, N.W.,
Washington, D.C. 20036, U.S.A.

Dear Mr Seifert,

Pipeline Rate Design.

I was interested in I.P.A.A.'s recent Motion for Leave to Interevene in the FERC's North East proceedings. I was particularly impressed by Mr Prather's lucid description and articulation of the rationale for the evolution of gas pipeline rate design in the U.S., and the sensible suggestions on future rate design.

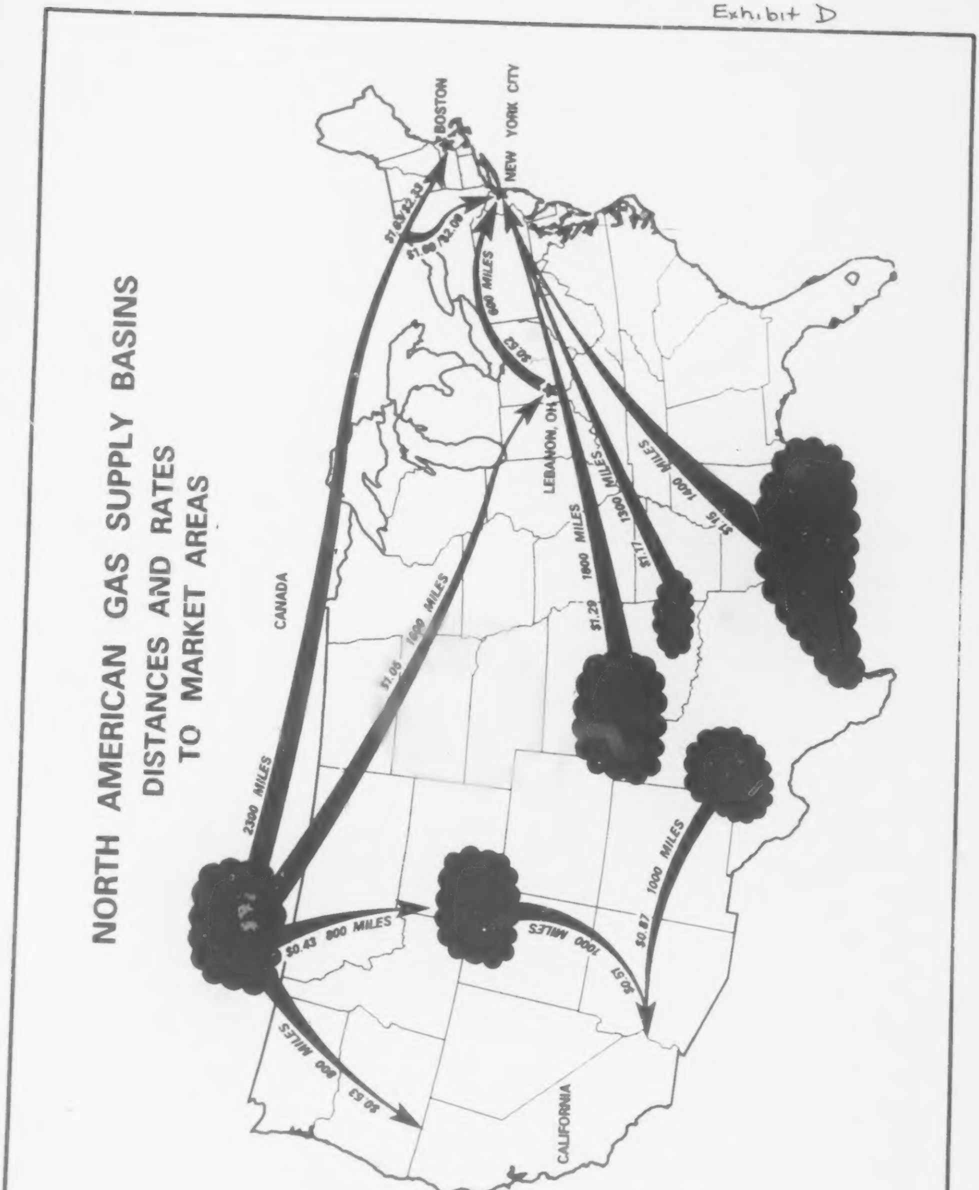
As a former Member and Chairman of Canada's National Energy Board, I have a great interest in US/Canada gas trade, and gas pipeline rate design. The fixed variable rate design was initiated in Canada long before the present competition in the gas trade, as we know it today developed. Canada was not therefore seeking any competitive advantage in the US market, but as Mr Prather points out, rather seeking to design rates in the way pipeline costs were incurred.

I am enclosing a copy of a recent talk that I gave on pipeline rate design. It reaches conclusions similar to those of Mr Prather, and adds incentives to encourage high pipeline productivity. I hope that these and other efforts will impel the FERC and the NEB to adopt rate designs more appropriate to a competitive north american market.

Yours truly,

C. G. Edge.

Exhibit D



NORTH AMERICAN GAS SUPPLY BASINS
DISTANCES AND RATES
TO MARKET AREAS

CANADA
BOSTON
NEW YORK CITY
LEBANON, OH
CALIFORNIA
2300 MILES
$1.65/$2.33
$1.88/$2.09
600 MILES
$0.53
$1.06 1800 MILES
$0.43 800 MILES
800 MILES
$0.53
1000 MILES
$0.57
$0.87
1000 MILES
$1.29
1800 MILES
1300 MILES
$1.17
1400 MILES
$1.75

The CHAIRMAN. Thank you very much, Mr. Hilliard. You did not disappoint us today. [Laughter.]

Mr. Ramsey, you say that if Canadian gas is such a good deal, why is there so much of it up there that is not being transported. Is that not really because they controlled the price at the border until 1984, and now they are just trying to build pipelines? I mean before 1984, the Canadian price was noncompetitive, and now it is a question of building the pipelines. Is that not the reason we are not inundated with cheap Canadian gas?

Mr. RAMSEY. Well, your fact is correct about 1984 on decontrolling the price. But there is also import capacity that is underutilized today from Canada. There is Canadian shut in, in the ground, and there is pipeline capacity into the U.S. that does not run full year-round. So there are other reasons besides the lack of projects or the lack of pipeline capacity.

The CHAIRMAN. NEB has an ongoing proceeding now. When do you expect the NEB proceeding to be completed?

Mr. RAMSEY. Well, the NEB's own estimate of when it will close hearings and then be able to produce an order on the trans-Canada facilities application would yield an order out of the NEB in the September/October time frame.

The CHAIRMAN. Now the NEB time schedule says that their certificate will expire by November of 1991 if you do not have gas flowing by that time. Do you not suspect that NEB would give you additional time on that? NEB and Canada are anxious to sell this gas. If there was a delay here because of an evidentiary hearing, NEB would not tell you that you had to get your gas flowing by November of 1991, would they?

Mr. RAMSEY. Well, I certainly cannot speak for the NEB. And clearly, if gas is not flowing November 1, 1991, and the projects are still being pursued, the gas exporters, I am sure, would ask for an extension of that deadline.

The problem is much larger than that, though. You have hit on only one thing that starts falling apart or coming under pressure if gas is not flowing in November of 1991. There is also all the question of the markets in the U.S. and the rate proceedings at the FERC, that the further they go along, the more difficulty we have in keeping the project together and keeping it in sync with what is happening north of the border.

The reason that the deadlines that we are discussing and the need for an FERC certificate in early July are, the dates, is because that was the original day for the National Energy Board to complete its proceedings and issue a decision on the Trans-Canada facilities. They had said originally that was going to be the end of June. They now have delayed it as a result of a court challenge on tolling methodology, and it has slipped two or three months.

The FERC and the National Energy Board have been working very closely together, we understand, to try to coordinate their activities to process these on as timely and coordinated a basis as possible.

The CHAIRMAN. One of the questions being considered by NEB is the question of incremental pricing as opposed to rolled-in pricing. Suppose they rule that you would have incremental pricing here, that the pipeline would have to be paid in effect not by the Canadian consumer. In that case, who would absorb the additional price? Would the Iroquois sponsors be prepared to do that?

Mr. RAMSEY. The Iroquois sponsors are sponsors of a gas pipeline that is a cost base regulated project, and the incremental pricing of transportation in Canada is something that would have to be worked out between the consumers of the product and the producers of the product. Who shares in what aspect of that I could not say.

The CHAIRMAN. Would that be worked out by contract?

Mr. RAMSEY. Yes. The purchasers that would use Iroquois to ship their gas would have to deal with the producers in Canada that they have gas purchase contracts with.

The CHAIRMAN. You mentioned hearings before NEB. What kind of hearings are those? Are those full-blown evidentiary hearings?

Mr. RAMSEY. I have not participated in them myself. Let me yield to Bob Reid, who has or will certainly appear in those hearings, to discuss those.

Mr. REID. Yes, Mr. Chairman. The hearing before the National Energy Board at the present time is to construct facilities on the trans-Canada system, some of which will be required to deliver the gas for Iroquois to the Iroquois export point. Those are full evidentiary type hearings.

The CHAIRMAN. They are full evidentiary type hearings?

Mr. REID. That is correct.

The CHAIRMAN. They will be finished with those, you expect, by September?

Mr. REID. The hearings are scheduled to be wrapped up in June with a decision in the September-October time frame.

The CHAIRMAN. I see. Do they deal with rate design and all of those things?

Mr. REID. The particular hearings under way right now are to examine the facilities to deliver gas eastward from Alberta. Some of that capacity is to be utilized by the Iroquois project.

The hearing will also examine the appropriate toll methodology to be applied for those facilities.

The CHAIRMAN. Now if they can do it by June, why could FERC not do it by June?

Mr. REID. I guess there are a couple of reasons, sir. First, the NEB hearing commenced some time ago. It commenced back in March.

Secondly, it is a repeat performance for the Iroquois panel up there. You will recall that we were originally scheduled to be in service back in 1989, and we appeared before an earlier facilities hearing up there. So much of our presentation is repetitive.

The CHAIRMAN. Has the incremental rate question been considered?

Mr. REID. Yes, sir. The issue of rolled-in versus incremental tolls has been a subject of Trans-Canada pipelines rate cases for quite some number of years. It is for that reason that the National Energy Board had determined back last fall that rate methodology would not be an issue because in each of those instances they have decided in favor of the rolled-in methodology. That, however, was subject to a court challenge, a successful court challenge, and the issue of rate methodology is back on the table.

The CHAIRMAN. Just one comment. It seems to me that Iroquois has always opposed a trial type hearing in this case, even of the expedited variety that could have been over well before the environmental review is completed. It even opposed a trial type hearing back in 1987.

Why has Iroquois opposed an expedited trial type hearing so much?

Mr. RAMSEY. Mr. Chairman, I think that is a mischaracterization of Iroquois' position. Iroquois has been through a full evidentiary trial type hearing in the State of New York, and it was as extensive and covered every aspect of need, rate design, cost and environmental that a Federal evidentiary hearing would have provided. All of that two and a half years of evidentiary trial hearing in the State of New York, all the information out of that trial is available to the FERC for their use in processing the Iroquois application.

We have not been against trial type hearings. We have been following the FERC's rules of the open season process where they are trying to avoid them because of the very lengthy delays and the costs associated with that.

If you compare the track record of the FERC in holding evidentiary hearings versus the NEB that we were just discussing, it has for some reason always taken them two or three years to do what NEB might do in two or three months.

The CHAIRMAN. Mr. Hilliard, the IPAA complains about the lack of a level playing field, and, as you pointed out about Will Rogers, it is always the money, what kind of money difference are we talking about here? If there is an uneven playing field, how much differential advantage would it give to Canadian gas?

Mr. HILLIARD. It is maybe a few hundred million dollars a year to Boston. You have a 2,300-mile pipeline in here. You have got about $1.93 rolled in, $1.33 incremental versus $1.15 rolled in from the Gulf Coast, $1.17 from Arkoma Basin, and $1.29 from New Commons.

There are U.S. projects in the mill. They are caught in the middle over at FERC, so there are incremental projects that can serve the northeast. There is a lot of gas—

The CHAIRMAN. Now, would those prices from the Gulf Coast exist if you built new facilities?

Mr. HILLIARD. You are talking about looping and compression and so on?

The CHAIRMAN. I am trying to get the size of, in effect, the subsidy. If you looped from the Gulf Coast, would you still have $1.15?

Mr. HILLIARD. I am not a pipeline expert. You will have to ask someone other than me for that.

The CHAIRMAN. There would still be a big subsidy, in effect?

Mr. HILLIARD. An evidentiary hearing would sure deal with all this stuff. It certainly would be a subsidy. You have to decide who is going to get hit. If it costs more to move gas from Alberta to the northeast, what are you going to charge the customers in the northeast because you have to sock the producers.

I want you to ask these gentlemen which they intend to do, or are they going to do both? Because if we operate a wellhead on a net back basis, we get what is left. When the LDCs take their cut, they pay the pipeline. The pipeline takes theirs and they give us what is left at the wellhead, I hope. Because that is $1.42 this month on the Gulf Coast, it is about 94 cents in Kansas and $1.15 in Oklahoma.

The **Chairman**. Do you want to answer that question?

Mr. **Ramsey**. I would like very much to respond to that.

Senator **Bradley**. May I interject?

The **Chairman**. Yes.

Senator **Bradley**. You might answer the question that Mr. Hilliard did not, which is if you are going to build a new pipeline what is going to be the price to the producer if you are going to do it on a competitive basis as compared to the price that the Canadians are prepared to take.

You are a pipeline builder. How much?

Mr. **Ramsey**. I was going to comment that I am in the pipeline business, and I probably know what the cost to deliver gas from Gulf Coast, Arkoma or whatever to the northeast is as well as anyone.

Rather than get into an argument or a discussion about what those rates are, the question I would have for Mr. Hilliard is this. If that is true, then why not go sell to those markets? If you have such an advantage in transportation rate as compared to Iroquois, why not go sell to those markets?

The customers of Iroquois are publicly known, and I would encourage Mr. Hilliard and his independent producers to go see every one of them and sell to those markets if he has such an advantage in transportation rate. It is one thing to get up and compare transportation rates from one region versus another region.

I would also submit that if you look at distance, why would there ever be any oil coming in from Saudi Arabia? There is certainly a lot of that coming in right now. You have to take into account a heck of a lot more than just distance or cost of transportation.

The **Chairman**. Before Mr. Hilliard answers that, let me see if I can get this straight in my mind. I think it is their claim that the fixed costs here are put into the demand charge, and the relative importance of the demand charge to an Iroquois, which is a big customer with a huge demand, is less than it would be to the Canadian consumers. So therefore, in effect, there is a subsidy of Iroquois by the Canadian consumer.

Is that correct?

Mr. **Hilliard**. That is the case.

The **Chairman**. And if that is so, they could not get that same kind of subsidy in effect in American because you are not going to get existing American consumers to subsidize through a demand charge the building a new pipeline.

Mr. **Ramsey**. Well, I do not know that that is exactly the fact. You may get existing American gas consumers to subsidize the building of a new pipeline if you take the cost of doing that and roll it into the existing costs of U.S. pipelines, and that is generally what is done when expansions are made on U.S. pipelines.

As far as the question of Canadian consumers subsidizing exports to the U.S., I do not think that is the case at all. Canadian consumers will also get very large increases in deliveries of gas from the western fields in Alberta into the eastern Canadian provinces as a result of Trans-Canada's facility application. Rolled-in rate methodology, whether north of the border or south of the border, whether it deals with pipelines or just about anything else, is common practice.

When you go out here to National to fly to Atlanta you do not pay more if you get on a new plane than you do on an old plane. Similarly, if an electric utility builds a new plant and the cost of producing electricity out of that plant is a whole lot higher than its average, you do not bill the customers a higher price simply because that plant costs more than the existing average.

So rolled-in pricing is not a subsidization of any one customer versus the other.

The CHAIRMAN. Mr. Hilliard, would you like to respond to that?

Mr. HILLIARD. To what? I mean, what part of it do you want me to respond to?

The CHAIRMAN. Well——

Mr. HILLIARD. NIPS was not rolled in. It is incremental, as I recall, and as far as the level playing field, Mr. Chairman, the level playing field is on the last 30 miles of a 2,000 mile line. We do not consider that really level, you know. Sorry about that.

The CHAIRMAN. Well, there is—you contend in effect there is a subsidy here.

Mr. HILLIARD. Yes.

The CHAIRMAN. Who pays that subsidy?

Mr. HILLIARD. The consumer will end up paying it. Either that or you have to go back and take it away from the producers.

The CHAIRMAN. I mean, the Canadian gas you say will be coming in more cheaply than you could——

Mr. HILLIARD. On the commodity price. A lower commodity price.

The CHAIRMAN. Well, the price to the consumer will be more expensive—I mean, the domestic gas cannot compete under this decision with Canadian gas because of a subsidy. I want to know who pays the subsidy.

Mr. HILLIARD. The consumer.

The CHAIRMAN. Which consumer? Domestic American or Canadian?

Mr. HILLIARD. If they roll it in, they will both have to pay it, and I think that is why the lawsuit against NEB right now.

The CHAIRMAN. Well, if they roll it in, that is right. The Canadian producer will. And if it is incremental, then the—then, of course——

Mr. HILLIARD. Then whoever gets the gas will have to pay it. And if it is incremental and those current consumers do not pay part of that cost, then that rate is going to up about 40 cents as you see per MCF.

The CHAIRMAN. All right. What you want is an opportunity to bring your experts in and show how it would be cheaper to transport gas from the Gulf Coast, the mid-continent or Arkoma or wherever then it would be with this Canadian gas.

Mr. HILLIARD. We want an open evidentiary hearing. There are only two issues. One is the rolled in issue and incremental, what is it really going to cost. Because the real cost, the Canadian portion of the line did not show up until February, and that is about $2.6 billion and growing. That was never handled in the open season process. It was never dealt with. It was never looked at.

Then when we went to open season process we were told wait your turn. This is not evidentiary. This just has to do with these various pipeline projects, 72 of them or whatever they started off with. And the other thing is the rate structure. There are only two real issues that have to be discussed. It would not take all that long for them to have an open hearing on it.

We would like to put our data on, put this sort of data on which we did in a hurry and talk about, you know, discrimination and cheaper alternatives, and we would like to have domestic pipelines able to be there, and we would welcome, Senator Bradley, your attention to it. We would love to talk to you about this issue.

The CHAIRMAN. All right. Senator Bradley.

Senator BRADLEY. Thank you, Mr. Chairman. I just want to clarify, Mr. Hilliard, on page 2 of your testimony you say that FERC and DOE failed to permit the IPAA to present evidence. Now, who is Mr. Prather?

Mr. HILLIARD. Prather (pronunciation clarificaiton)——

Senator BRADLEY. Prather.

Mr. HILLIARD [continuing], is a gas rate consultant here in Washington.

Senator BRADLEY. Was he a consultant for the IPAA?

Mr. HILLIARD. Yes.

Senator BRADLEY. So he did submit evidence, is that not correct?

Mr. HILLIARD. Well, let me tell you how it was handled. DOE said, Wait a minute. This is a rate-making matter. This really is not our territory. You need to go to the FERC. FERC said in the NIPS case, Sorry, the free trade agreement keeps us from talking about free trade.

Senator BRADLEY. But Mr. Prather was representing IPAA in this testimony?

Mr. HILLIARD. Yes, yes.

Senator BRADLEY. And his testimony was IPAA and it was——

Mr. HILLIARD. As far as I know, yes.

Senator BRADLEY. Okay, thank you. You are familiar with the Brooklyn Union, et cetera, obviously or you would not be here, right? I mean, you opposed it, so you are obviously—got to be familiar with what you are opposing.

Mr. HILLIARD. I am an independent. I am supposed to know a lot about a lot of things, but this is, you know, rate making and pipelines is a little bit out of my territory.

Senator BRADLEY. Well, let us just take some of the—not get too complex here.

Mr. HILLIARD. All right.

Senator BRADLEY. These contracts are for 15 years, and they take into account changes in prices of alternative fuels in the market and lower gas prices, basically, and that is how you get to the border price, right, which changes. 15 years in the changing border price.

Mr. HILLIARD. You have price-sensitive triggers is what you are saying.

Senator BRADLEY. Right. Now, do you know if IPAA members entered into contracts like that with the Northeast, with any northeast LDCs?

Mr. HILLIARD. We have not seen any such contracts.

Senator BRADLEY. Why not?

Mr. HILLIARD. I really do not know because right now we are selling on a 30-day spot basis. That is not really much fun. It goes up. It was $2.40 in January. It is $1.40 now. So we have seen more than $1 decline since January.

Senator BRADLEY. So basically you do not want to enter into longer term contracts?

Mr. HILLIARD. We have not been offered that type of deal. I have not seen any. No one has come to me and offered me a long-term contract with all those cute things in it, a 15-year contract, 100 percent takes into a pipeline that is owned two thirds or a third by distribution companies guaranteeing 100 percent takes, price-sensitive triggers.

Senator BRADLEY. But the fact of the matter is you do not know—no one member of your organization has entered into any similar kind of contract in terms of length of time and in terms of agreement on changes in prices?

Mr. HILLIARD. Well, we have over 5,000 members. I do not know of any, but I do not know of anyone that has been offered one.

Senator BRADLEY. Let me if I can come back—basically you——

Mr. HILLIARD. I would love to see one.

Senator BRADLEY. You supported decontrol, right?

Mr. HILLIARD. Absolutely.

Senator BRADLEY. Because you did not want FERC interfering with private companies?

Mr. HILLIARD. For a whole variety of reasons.

Senator BRADLEY. What do you think about FERC reviewing the conditions of gas sales contracts that your producers signed?

Mr. HILLIARD. I think FERC does not really care what I think. They do not care what I think. They have not asked me.

Senator BRADLEY. Well, but we care. That is why I am asking.

Mr. HILLIARD. I understand. We can participate in rate hearings at the cost of about $300,000 per hearing, and they take about two years. There are about 33 of them pending right now. For $10 million we can get in this ball game.

Senator BRADLEY. Okay. I take your point.

Let me ask Mr. Ramsey again, if you did build the new pipeline from Louisiana, Oklahoma, what would it cost?

Mr. RAMSEY. Well, there are at least two proposals out there for new incremental domestic capacity. One has been filed, one is being discussed with potential customers, and the incremental cost of transporting gas on those pipelines from domestic sources in Louisiana, Texas and Oklahoma varies from 83 cents to $1.50 plus fuel in the proposals that I have seen.

Senator BRADLEY. The cost of what? What is that number?

Mr. RAMSEY. The transportation costs, forgetting the gas costs, but the transportation cost varies from 83 cents to $1.50 plus the fuel associated with moving the gas.

Senator BRADLEY. If you were going to construct this pipeline and you had to get your gas sold ultimately competitively, what would be the price to the producers and how would that compare to the price to the producer in the Iroquois-Canadian agreement?

Mr. RAMSEY. Well, Senator Bradley, I think you have hit upon one of the biggest problems that both pipeline companies and producers face right now, and that is the market is determined by 30-day spot prices delivered into the market, and that is the ceiling and the cap under which we must all currently operate, and those delivered prices today, as Mr. Hilliard said, wellhead prices, are $1.45, $1.50 in the Gulf Coast and delivered prices are in the $1.85 to $2.00 range. But that is 30-day spot gas.

The difficulty is to go to the customer who is buying a lot of gas on a 30-day basis and say I want to sign you up for a long-term 15 or 20-year deal, and the cost is going to be a whole lot more than what you are paying today, and those customers, most of them say, how will I ever justify that to my state commission, and the answer is long-term security of supply.

And I would submit that the producer has just as much if not more responsibility for marketing his product than he does to sit back and wait until somebody calls and offers him a price that he likes. And what I am saying is there are domestic pipeline proposals out there today being discussed, and there are going to be market opportunities for domestic producers to sell more gas into the Northeast over the coming years.

And the smart thing for domestic producers to do is to get aggressive and to go after those markets and contact the Public Service Electric and Gas Companies and the others in the Northeast who need further increments of gas down the line.

Senator BRADLEY. And again, just so that we can focus on this clearly, a full evidentiary hearing in your view kills the prospect of getting gas into the Northeast from this Iroquois project?

Mr. RAMSEY. Certainly on a timely basis there is no doubt about that.

The CHAIRMAN. Senator Domenici.

Senator DOMENICI. Mr. Chairman, I do not know that I have any questions, but if my thought as to what concerns me as I see this little bit of evidence unfold prompts anybody to answer, fine. If not, I just want to close by stating my concern on the record.

Frankly, the fact that the local distribution companies own a third of this pipeline is a very significant fact in my opinion because they have encumbered themselves as a distribution company with paying for a third of this pipeline, and that puts them in a position, seems to me, of not making their sales area and their customers available, not making available to them and their sales area and customers gas from other sources than this pipeline.

Senator DOMENICI. I believe that is going to end up being a bad deal, or could. It might not because you may have lucked out in terms of where the current market is, which is the only thing that makes your long term contracts neat for these consumers.

If the market is changing and if it was going down as it has and you stuck these consumers with these rates, it seems to me they could be getting a lesser deal than down the line a few years when some others wanted to serve the area. Those LDCs are not going to be able to buy from any other pipeline. They are going to have to buy from this pipeline.

What we have been busy doing in this country is turning that around. We have been busy turning it around so that the producer of the gas was selling the gas wherever he could sell it. That has been a premise.

Interestingly enough, I am sorry that Senator Bradley left because he pushed this very hard. Some of us in the oil patch and gas patch did not like the idea because the other arrangement lent itself to very long term contracts and take or pay. It turned out they all were on the up side, so we wanted to do away with them, and we did. We took the independents and cancelled all those contracts and said what we will give you is to get out there and sell it yourself at the best possible price. Now what we are going to do here is say the opposite, because obviously the big buyer is the LDC. He is going to expand his area; he is going to serve them with natural gas.

From where is he going to buy his natural gas? I cannot tell from what wells, but he is going to buy it from that pipeline because he has to pay for that pipeline. It appears to me that others who would want to come in with pipelines or enhancement of the existing pipelines are not going to sell to those local distributing companies that own a pipeline.

Now if that is what an evidentiary hearing would reveal, that ought to be looked into, it seems to me. I am not telling anybody what to do, but that is not the direction in which we have been moving in this country in order to assure the consumer of the best possible deal.

Now I am willing to say obviously if there is no supply and along comes somebody with a multi-billion dollar pipeline and says we want a permit to build that, I guess somebody ought to seriously say, well, let us look at it. Maybe we have to give them a permit. It seems to me when you then build in that those local distribution companies have to pay for that pipeline, if there are alternatives you ought to be seriously looking at the alternatives. That comes to me as I look at this, and if you care to comment, fine.

Mr. Ramsey. I would like to comment. I think the representative from the Department of Energy hit on this a little bit. The State regulatory commissions in the States of New York, Connecticut and New Jersey where the LDCs about which you are talking do business will certainly look at the purchasing practices of the LDCs who are investors in the pipeline as well as shippers on the pipeline.

I think the LDCs are very much aware of the risk that they are under as both owners as well as shippers and that they know those regulatory commissions will be looking over their shoulder every month to see if their gas purchasing decisions are based upon their financial involvement in this project.

Senator Domenici. Let me tell you, Mr. Ramsey, that is good theory, but the best case in the country for the fact that it did not work that way is California and New Mexico gas, because the exact opposite occurred. They are a very, very tiger type commission. We are for the consumer. They said no to cheaper gas and yes to paying for the pipeline cost first, and so our gas did not get into those transmission lines. The exact opposite of what you say would happen happened.

With the most offensive-minded commission in the country that is trying to get the consumer the best deal, when offered cheaper gas in the exact situation I have described here, the answer was, well, it costs so much for the pipeline, no dice because it was coming from another source. So I am not at all sure that is protection. I am not saying it could not be, but I am not sure it is.

I have nothing further.

Mr. Hilliard, do you want to comment on that?

Mr. **Hilliard**. I would say that if there are serious time constraints for Iroquois, then they should not have dragged their feet for three years on evidentiary hearings. Some of that $25 or $30 million was used certainly to stop evidentiary hearings and scrutinize fairness and availability of cheaper alternatives, I will tell you that.

Two years ago this month the Department of Energy published its assessment of U.S. natural gas reserves and resources showing nearly 600 trillion cubic feet available at a wellhead price of less than $3 in the Lower 48. So domestic U.S. producers and independents are delighted to see growing markets in the northeast or anyplace in this country. That is an absolutely joy to us. I followed, I tracked those numbers, and I would be happy to furnish you current data on those numbers. I cannot say that I see signs of shortages.

I am sorry Mr. Bradley left also. In New Jersey, if you look at the numbers from the EIA, looking at 1989 vis-a-vis 1984 you will see some interesting prices there. You will see that the city gate price in New Jersey was down 19.5 percent, the burner tip price down 15.3 percent, the residential prices down more than 10 percent, commercial prices down almost 19 percent, industrial prices down 28.5 percent, and utility prices in New Jersey 1989 vis-a-vis 1984 down 43 percent. They were really hurting.

Now if that is a sign of a shortage in New Jersey, they better hope to hell they never have a surplus. That is all I can tell them.

If those people show is a market responsive take-or-pay or take-or-release contract, which is better than a take-or-pay, and put it into a system owned by the distribution companies which guarantee the takes, I guarantee there will be a waiting list of independents trying to sign up for that deal, but we have not been offered such a deal.

Gentlemen, I thank you for bringing that to our attention.

The **Chairman**. Mr. Ramsey, you mentioned that the local PUC would look into the purchasing practices as gas is purchased from time to time under this contract and would determine whether the price is proper and whether the amount taken is proper.

Is that what you said? Did I understand that?

Mr. **Ramsey**. That is what I understand the role of the State PSCs to be, that is correct.

The **Chairman**. Now as I understand it, once this section 3 permit is given, then the question of prudence is out the window. That is subsumed, to use the terms of that decision.

In addition to that, once this contract is approved they are in effect agreeing to take all their gas from Iroquois at a price which is determinable under that contract that relates with the price of fuel oil in the northeast, I believe. So what is there for the PUC to review once this contract is approved?

Mr. **Ramsey**. I do not believe that the issuance of the certificate by the FERC eliminates any prudence oversight on the part of the gas supplies going to the local distribution companies. The local distribution companies are under prudence reviews constantly for their purchasing practices from the various sources they have available to them whether it is spot gas, pipeline gas, Canadian import gas, which many of them already buy directly, and they have to make the showings to the public utility commissions that their purchasing practices each month were prudent or low cost and in the best interest of the consumer.

The CHAIRMAN. What I mean is that DOE's order authorizing the gas imports indicates that the section 3 determination would subsume the question of prudence and leave the PSC without legal authority on this issue.

Mr. RAMSEY. I am not an attorney, but I would suspect that the public utility commissions in the states in the northeast think there is nothing that has been subsumed to the DOE as far as prudent challenges of the purchasing practices of the LDCs they regulate.

The CHAIRMAN. In any event, it seems to me once they approve this contract which provides for gas at a determinable price, there basically is no competition because you have made the deal at that point. It is too late. There is very little left to review. You say you can always get spot gas here or there, but you are building the pipeline and there is no other pipeline available. That is the point, is it not?

Mr. RAMSEY. I think the customers of the Iroquois project have numerous other opportunities available to them today and will have more opportunities available to them in the future as to where they buy gas.

What I am saying is that the existence of that pipeline and the existence of a DOE order authorizing the import of gas through that project does not mean that the local regulatory commissions cannot go in there and truly inspect everything they do on purchasing gas; and if they find them favoring purchasing from a project in which they have an investment, they can take dollars away from them in any number of ways.

The CHAIRMAN. Now if there is a high demand charge and a low commodity charge relatively speaking with Canadian gas, is that going to make the LDC favor the Iroquois gas over domestic gas which may be the same total price but a higher commodity price?

Mr. RAMSEY. I cannot speak for the purchaser. I am not a purchaser. I am an equity investor in the project, but clearly each month they would look at the incremental cost of gas. What we are talking about here is a project, the overall costs of which have to be borne by the LDCs and their customers. It is beyond me to understand why the public service commissions if they see some discrimination or some favoring of activity cannot correct that at the State level.

The CHAIRMAN. Mr. Hilliard, I spoke with the chairman about their rate design guidelines and about trying to make that applicable immediately and nationwide rather than on a case-by-case basis.

Would that help to level the playing field here?

Mr. HILLIARD. We would love to see a rate structure like the Canadians have. We much prefer that structure, but we want to do it on a generic basis and not on a case-by-case. We cannot afford to fight it case by case daily. We cannot wait. We do not have the time, and we do not have the money.

The **Chairman**. Your problem here is really not so much with Iroquois as with the precedent which it sets: is that correct?

Mr. **Hilliard**. Canadian gas is fine. It is great. It is a great comfort factor. We look forward to seeing it. It is not a problem, not per se. Our problem is transportation rates. It is the problem of Canadian gas coming into the northeast on a favored rate structure and backing out U.S. gas and forcing the wellhead price down further. That is the problem. That is right. Our problem is not with Iroquois. It is with the rate structures, the disparity between Canada and the U.S.

The **Chairman**. How would you remedy that?

Mr. **Hilliard**. I could not. You would have to ask Mr. Allday and the FERC to see if they could go to a fixed variable rate and something comparable to that of Canada. I guess there are various ways that you could fix it.

The **Chairman**. Do you have a preferred way?

Mr. **Hilliard**. Just a rate reform. We filed a petition months and months ago for a rate reform. We have been advocating total overhaul of the U.S. rate system for several years.

Mr. **Ramsey**. Mr. Chairman, could I jump in on this point?

The **Chairman**. Yes.

Mr. **Ramsey**. I think there may be an opportunity right here in this line of discussion for a way to address the issues that both of us are trying to address. What we want is fast action on Iroquois. What Mr. Hilliard wants is a determination as to whether or not there is existing rate discrimination.

The solution would seem to me to be the FERC can cause a generic rate action, it can cause a pipeline specific rate action anytime it wants to by filing under section 5.

Even more than that, Iroquois in its application has offered itself up for rate reviews where exactly these issues can be addressed at times prospective in the future. Here is a way to solve or at least investigate whether or not there is a rate discrimination problem that favors Canadian gas over domestic gas without slowing down the processing of this Iroquois certificate.

I would submit that the partners and the investors in Iroquois would be glad to subject themselves to such a generic proceeding as long as we can go ahead and proceed with the application that is before them now because I am confident that the result of that will not be something that would cause Iroquois not to be billed, and if Mr. Hilliard is accurate in his statement that his problem is not Iroquois but an unlevel playing field, here is the way to fix it. He can level the playing field for all pipelines in one fell swoop after the fact.

The **Chairman**. That would be a generic proceeding engrafted upon the Iroquois, but your suggestion is not to delay the particular permit now being applied for?

Mr. **Ramsey**. Exactly.

Mr. **Hilliard**. Excuse me. [Pause.]

The **Chairman**. The staff is pointing out the difficulty of getting the other pipelines into this same proceeding and of getting a quick decision on this, some kind of Order 500 type decision which is a nationwide application.

Would you like to comment on that, Mr. Hilliard?

Mr. HILLIARD. Mr. Ramsey was talking about the future, but the future is an indefinite term particularly if you are an independent selling on the 30-day spot market.

I am almost 65 years old, and I cannot eat health food because I need the preservatives in regular food. I cannot deal with this future deal. We have been with that future scenario with the FERC and DOE and so on, and we have not done very well with it. We want to see something done about it now or see something done with the Iroquois now.

If that is what it takes to bring it about, then we would urge you to do whatever you have to do. The pipes need to compete on an equal basis. The North American gas market is a wonderful concept, but it can have two different transportation rates.

Mr. RAMSEY. Mr. Chairman, I think the FERC could implement this either on a blanket basis by causing pipelines to come forward for rate review, or they could do it on an incremental basis or an ad hoc basis as each pipeline comes forward for a rate review, and all pipelines that perform the merchant function and have a purchase gas adjustment clause have to file at least every three years.

So by the end of three years from today, every pipeline just in normal processing of rate reviews would have been subjected to this new rate modification. That is exactly what the FERC is proposing to do, as I understand it, in their rate design policy initiative; that is, subject each pipeline's standard rate proceeding to the new rules and regulations that they are investigating in the rate design policy initiative. They can add this as part of that.

The CHAIRMAN. It would take three years to get that started in some cases, and then the review would require a delay as well.

Senator Domenici.

Senator DOMENICI. I am beginning to kind of understand a little bit, and I thank you again for calling the hearing. I will just close by saying I hope for the benefit of the northeast that is going to be served by this that the deals that were struck and the contracts that are going to be entered into are good for the northeast for a long time. Obviously those who have put it together think it will be.

I think it is put together to avoid future regulations and future commission activity because under the Narangansett decision once you have a Federally approved rate local commissions are out of it, and I now note that the LDCs even went up into Canada and made the deal to buy the gas in Canada, which I guess is all to take advantage of an interpretation of the Free Trade Agreement, the more I see it.

So if it turns out that amortizing the debt incurred for this pipeline of which the LDCs own a piece which compels them, in my opinion, to buy gas in Canada which they have contracted for in Canada, if that turns out to be a good deal, fine. If it turns out not to be, they are going to be before us saying this process did not work, did not protect anybody, and we will not be selling domestic gas in competition with it. That is how I see it.

I have no solutions, either, except that it begins to unfold in my mind that this is a very intriguing and interesting way to get around future regulation and gamble on the market as it is today as to future prices for the consumer and at the same time not make it very easy for domestic natural gas to get into that area or for alternative pipelines to get into that area. I think that is kind of about the way it seems to me.

Thank you very much, Mr. Chairman.

The CHAIRMAN. Thank you, Senator Domenici.

Well, I hope it has been clear that the purpose of this hearing has been not to delay the Iroquois decision nor to oppose the Iroquois pipeline. To the contrary, we want to expedite the flow of gas to the northeast. We want adequate supplies to the northeast. That has been the history of this Chairman and of this committee.

It is also our very strong feeling, my very strong feeling, that the spirit of Order Number 256, which is a level playing field, ought to be the order of the day for all pipelines and for all producers, and we do not want under some technicality for American producers to be disadvantaged. The American producers say they are not only disadvantaged but they are not given the chance to prove their disadvantage because the only way you can do that is through a full hearing.

These are difficult questions, and I hope that those who are charged with the duty of coming up with policies, including this committee, will do the right thing and will level the playing field, will encourage domestic production through whatever means consistent with the Canadian Free Trade Agreement, and will help at least to provide for fairness and equity between the different producers.

We will keep the record open for an additional 30 days. There will be additional questions in writing which we would like to submit to you gentlemen as well as the other witnesses.

With that, the hearing is adjourned. Thank you very much.

[Whereupon, at 12:30 p.m. the hearing was adjourned.]

[COMMITTEE NOTE.—Due to the voluminous nature of the hearing record, and in particular the number of post-hearing submissions received by the Committee, certain materials have been omitted from the printed hearing record. In general, the omitted materials are either duplicates or merely supplement other materials that have been included in the printed hearing record. The unprinted materials remain available for public inspection in the files of the Committee.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D C 20426

CHAIRMAN

June 5, 1990

Honorable J. Bennett Johnston
Chairman, Committee on Energy and
  Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Thank you for your letter of May 14, 1990, enclosing questions for the record of your Committee's May 3 hearing to consider natural gas markets in the northeastern United States.

I appreciate your interest and am pleased to submit the enclosed responses prepared by the Commission staff to your questions as well as those submitted by Senators Bingaman and Domenici.

Senator Domenici requested that I provide the Committee with a copy of the March 30, 1990, memorandum prepared by the Commission's Office of General Counsel entitled Options for Addressing Rate Design Issues in Natural Gas Pipeline Construction Projects Involving Imported (Canadian) Natural Gas. This memorandum will be submitted under separate cover.

If you have any further questions or need additional information, please let me know.

Sincerely,

Martin L. Allday

Martin L. Allday

Enclosure

Questions for Chairman Allday

From Senator Johnston

1. In response to a question about whether expedited evidentiary hearings could be held in the Iroquois certificate proceeding, you commented that this depends on the scope and complexity of the issues set for hearing, but that it could take up to three years.

   A. Is it not true that the Commission, in its hearing orders, specifically prescribes the issues to be heard by an Administrative Law Judge (ALJ) and that the Commission can thereby limit the scope of an evidentiary hearing that it might order?

Answer:

It is possible for FERC to expedite the hearing process by prescribing certain issues to be heard. The Commission has used this approach on occasion. However, the effectiveness of this approach is limited by the circumstances of each case. More specifically, whether or not a hearing can actually be expedited depends on the nature, scope and complexity of the issues as they appear at the time a hearing is ordered and on the way the issues evolve in the course of the hearing.

   B. Is it not true that the Commission may order an ALJ to complete an evidentiary hearing and issue an initial decision by a date certain? For example, in Independent Petroleum Association of Mountain States v. Panhandle Eastern Pipe Line Co., 36 FERC ¶ 61,282 (1986), the Commission ordered the ALJ to expedite the hearing and issue an initial decision within three months. Also, in Utah Power & Light Co., 41 FERC ¶ 61,283 (1987), the Commission ordered an initial decision in a complex merger case within six months.

Answer:

In the past, the Commission has expedited particular hearings by ordering the ALJ to issue an initial decision by a date certain. Whether this can be done successfully depends on the nature, scope and complexity of the issues and the extent to which issues can be narrowly defined beforehand. Thus, after pre-hearing conferences or after the filing of prepared testimony, the time limit may have to be changed if it becomes apparent that the time limit is not realistic.

Additionally, the Commission must balance the need to expedite proceedings with the due process rights of all affected parties. Also, if an attempt to expedite the proceedings results in an incomplete record, further proceedings may be required to complete the record, causing further delay. For example, this occurred in a Transcontinental Gas Pipe Line case involving proposed rates and conditions for open-access transportation. The Commission severed one issue, related to transition costs and set it for hearing (36 FERC ¶ 61,287 (1986)). In December, 1986, the Commission ordered that an initial decision be issued by February 15, 1987 and ordered an expedited briefing schedule (37 FERC ¶ 61,289(1986)).

On September 15, 1987, the Commission issued an order affirming the initial decision, in part, and remanding other issues for further hearings (40 FERC ¶ 61,232(1987)). The Commission found it necessary to order the remand because there was confusion on the part of the parties regarding the scope of the hearing and an insufficient record had been developed during the hearing. In that case, attempting to expedite the proceeding further delayed resolution of the case.

Also, putting a case on an expedited hearing schedule can interfere with processing the Commission's remaining caseload.

2. In your testimony and in answers to the Committee's questions, you described the results of the Commission's open season proceeding. Please provide the Committee with a status report on the projects that emerged from the open season proceeding. In particular, please indicate:

   A. the procedural status of the certificate applications;

   B. the markets to be served, the volumes of gas to be provided and sources of such gas;

   C. the projected in-service dates for the projects; and

   D. any applications to expand capacity to serve the Northeast received subsequent to the open season along with the same information requested for the open season projects.

Answer:

Attached are a docket list and a summary table of the Northeast Projects with the information you request. The docket list (Table 1, pages 1 through 4) shows each of the Northeast projects, its corresponding application docket numbers, and company names. The summary table (Table 2, pages 1 through 5) divides the projects into three groups -- the approved projects, the pending projects, and those projects filed after the open season process had ended.

Ten of the open season projects remain pending. Also, five new projects have been filed since the open season.

3. In answer to a question from the Committee, you responded that the Office of Pipeline and Producer Regulation had informed you that existing interstate pipeline capacity to the Northeast was in most cases utilized to capacity. Would you please provide information detailing this answer including the identification of particular pipelines, the markets they serve and the producing regions they access, and seasonal capacity utilization.

Answer:

In my earlier response I stated that the Office of Pipeline and Producer Regulation had informed me that existing interstate pipeline capacity to the Northeast was, in most cases, utilized to capacity during peak periods. OPPR examines each pipeline certificate application to determine whether the proposed facilities are appropriate. OPPR uses a computer simulation model to make this determination. The starting point for such studies is to determine whether capacity in existing facilities is utilized to capacity on peak days. Staff's examination of all of the Northeast projects to date indicates that, on a peak day, the existing facilities are, in most cases, fully contracted to serve existing customers as shown in the attached Table 3.

In addition, the Department of Energy's Energy Information Administration prepared a study in August 1989 entitled, "Assessment of Pipeline Capacity to Transport Domestic Natural Gas Supplies to the Northeast." This study shows the 1987 peak day capacity utilization (with the exception of Texas Eastern Transmission Company) of the Northeast pipelines. The attached Table 4 shows the conclusions of EIA's study updated with FERC information on the 1989 peak day utilization for the Texas Eastern system.

NORTHEAST PROJECTS

Table 1
Page 1

Project	Docket No. - Company
1. DOMAC Excess LNG (Issued 3-21-88)	CP88-160-000 Distrigas CP88-161-000 Distrigas
2. Commonwealth (Issued 6-29-88)	CP87-492-000 Algonquin
3. Niagara Spur I (Issued 6-30-88)	CP87-131-000 Tennessee CP87-131-001 Tennessee
4. CNG Storage (Issued 7-27-88)	CP87-447-000 CNG
5. PennEast Sales (Issued 7-27-88)	CP87-4-000 PennEast CP87-4-001 PennEast/TETCO CP87-4-002 PennEast/TETCO CP87-5-000 CNG CP87-28-000 TETCO CP87-28-002 TETCO
6. ORU (Issued 7-27-88)	CP87-339-000 Columbia
7. Biddlecum Road (Issued 7-27-88)	CP86-344-000 CNG
8. Beverly Salem (Issued 9-16-88)	CP87-85-000 Tennessee
9. New Jersey/Providence Replacement (Issued 9-16-88)	CP88-164-000 Columbia
10. Niagara Spur II (Issued 10-3-88)	CP87-131-000 Tennessee CP87-131-001 Tennessee
11. Ocean State (Issued 10-3-88)	CP87-132-000 Tennessee CP87-132-001 Tennessee
12. Braintree (Issued 5-18-89)	CP88-167-000 Algonquin
13. NOREX (Issued 5-18-89)	CP87-358-000 Tennessee CP87-358-001 Tennessee CP87-428-000 CNG CP87-428-001 CNG
14. New Jersey/Providence (Issued 7-17-89)	CP88-129-000 Columbia CP88-129-001 Columbia CP88-163-000 Columbia

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Project	Docket No. - Company
15. Providence (Issued 5-18-89)	CP87-75-000 Tennessee
16. APEC I	CP87-5-003 TETCO/CNG
(Issued 6-7-89)	CP87-92-003 TETCO/CNG
	CP87-312-002 TETCO/CNG
	CP87-197-001 TETCO/CNG
	CP88-388-001 TETCO/CNG
17. APEC II/III	CP87-5-002 CNG
(Issued 6-7-89)	CP87-312-001 CNG
	CP87-313-001 CNG
	CP87-314-001 CNG
	CP87-554-001 Algonquin
	CP88-197-002 CNG
	CP88-388-002 CNG
	CP89-6-000 Transco
18. Niagara Import Point Phase I (SS-2)	CP88-194-000 National Fuel Penn-York
(Issued 7-27-89)	CP88-194-001 National Fuel Penn-York
	CP89-7-000 Transco
	CP89-7-001 Transco
	CP88-195-000 PennEast/CNG TETCO
	CP88-195-001 PennEast/CNG TETCO
	CP88-195-002 PennEast/CNG TETCO

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Project	Docket No. - Company	
19. Niagara Import Point Phase II (Issued 5-2-90)	CP88-92-000	Transco
	CP88-92-001	Transco
	CP88-94-000	National Fuel
	CP88-94-001	National Fuel
	CP88-171-000	Tennessee
	CP88-171-001	Tennessee
	CP88-194-000	National Fuel Penn-York
	CP88-194-001	National Fuel Penn-York
	CP88-195-000	PennEast/CNG TETCO
	CP88-195-001	PennEast/CNG TETCO
	CP88-195-002	PennEast/CNG TETCO
	CP88-195-005	PennEast/CNG TETCO
20. APEC IV (Approved 5-30-90)	CP87-5-002	CNG
	CP87-312-001	CNG
	CP87-312-004	TETCO
	CP87-312-006	TETCO
	CP87-313-001	CNG
	CP87-314-001	CNG
	CP87-554-001	Algonquin
	CP88-197-002	CNG
	CP88-388-002	CNG
21. Niagara Import Point Phase III	CP88-171-001	Tennessee
	CP88-187-001	Algonquin
	CP88-194-001	National Fuel Penn-York
	CP88-195-002	PennEast/CNG TETCO
	CP89-7-001	Transco
	CP89-710-000	Transco
	CP89-711-000	TETCO
	CP89-712-000	CNG
	CP89-892-000	Great Lakes
22. Public Service	CP88-172-000	Tennessee
23. CRP/LNG Reinstatement	CP87-94-004	TETCO

NORTHEAST PROJECTS

Project	Docket No. - Company
24. PennEast CDS	CP88-180-000 TETCO
	CP88-180-002 TETCO
	CP88-185-000 Algonquin
	CP88-185-002 Algonquin
25. Iroquois/Tennessee	CP89-634-000 Iroquois
	CP89-634-001 Iroquois
	CP89-815-000 Iroquois
	CP89-629-000 Tennessee
	CP89-629-001 Tennessee
	CP90-639-000 Tennessee
	CP89-661-000 Algonquin
	CP89-661-001 Algonquin
	CP89-1263-000 TETCO
	CP89-1339-000 BUG, ConEd & LILCO
26. Champlain	CP89-646-000 Champlain
	CP89-654-000 Champlain
	CP89-661-000 Algonquin
27. ANR	CP89-637-000 ANR
	CP89-637-001 ANR
	CP89-637-002 ANR
	CP89-635-000 Columbia
	CP89-635-001 Columbia
	CP89-638-000 CNG
	CP89-638-001 CNG
	CP89-661-000 Algonquin
	CP89-661-001 Algonquin
	CP90-687-000 Transco
	CP90-688-000 Texas Gas
28. Indiana-Ohio	CP88-178-000 Indiana-Ohio
	CP88-178-002

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NORTHEAST PROJECTS
APPROVED

Project	Date Issued or Approved	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
1. ORU	7-27-88	Increase existing contract demand sales	1.2	100/0	Service for NY LDC (local distribution company	Not Applicable
2. Biddlecum Rd	7-27-88	Increase in firm sales	44.2	100/0	"	"
3. Commonwealth	6-29-88	Firm 20-year transportation for peak day use	40.0	100/0	Service for MA LDC	"
4. PennEast Sales	7-27-88	Firm transportation and sales from system supply, storage service	123.0	96/4	Transportation for 5 LDC's in NY and NJ and storage for 1 other LDC	"
5. Beverly-Salem	9-16-88	Pipe replacement to firm-up previously authorized transportation service	10.5	0/100	Service for MA LDC	"
6. Niagara Spur I	6-30-88	System supply capacity expansion	40.0	0/100	Existing customers and market	"
7. Niagara Spur II	10-3-88	System supply capacity expansion	110.0	0/100	"	"
8. CNG Storage	7-27-88	Firm storage service	80.0	96/4	Storage service by CNG for Tennessee	"
9. DOMAC LNG	7-21-88	Sale of LNG for peaking purposes	150.0	Imported LNG	Northeast customers	"
10. NJ/Providence Replacement	9-16-88	Replacement of existing mainline facilities to restore capacity	59.7	----	Existing customers and market	"
11. Ocean State	10-3-88	Firm 20-year transportation service	50.0	0/100	Electric generation facility in RI	"
12. Braintree	5-18-89	Firm 20-year transportation service	21.7	92/8	Electric generation facility in MA	Not Applicable

Table 2
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NORTHEAST PROJECTS
APPROVED

Project	Date Issued or Approved	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
13. Norex	5-18-89	Firm sales increase and transportation service	91.4	96/4	10 existing LDC's in MA, NH, CT and RI	"
14. Providence	5-18-89	12-year sales service	30.0	96/4	Service for LDC in RI	"
15. APEC I	6-7-89	Restore certificated capacity on Texas Eastern's system	554.3	100/0	Provides capacity for CNG under APEC II/III below	"
16. APEC II/III	6-7-89	Provide transportation, storage or sales service	395.0	100/0	Storage for 11 LDC's and 2 cogenerators in RI, NY, MA, PA and CT. Sales to 11 LDC's by CNG, with Transportation by Transco, Algonquin and Texas Eastern.	"
17. APEC IV	5-30-90	Transportation and storage service	99.1	100/0	Service for 6 LDC's in MA, NJ, PA, and NY	4-1-91
18. NJ/Providence	7-17-89	Provide sales and transportation	80.0	100/0	Sales to 2 LDC's in NJ and RI and transportation of gas to them	"
19. NIPS (SS-2)	7-27-89	Provide storage service for 11 Bcf and related storage transportation of 100 MMcf/d	100.0	93/7	Services provided for 6 LDC's and 2 cogenerators in NY, NJ and PA	"
20. NIPS II	5-2-90	Firm transportation service	132.2	19/81	Service for 3 LDC's and 4 cogenerators in CT, MA, MD, NJ and NY	"

NORTHEAST PROJECTS
PENDING

	Project	Date Filed	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
1.	NIPS III	1-15-88	Firm transportation service	360.4	7/93	Service for 3 LDCs, 9 cogenerators and 1 electric generator and 2 pipelines in NY, NJ, PA, MA, RI, and VA	11-90
2.	Public Service	1-15-88	Firm sales service	40.0	96/4	Service for an LDC in NJ	11-91
3.	CRP/LNG Replacement	11-10-88	Restoration of capacity	102.1	----	Service for 5 LDC's and 1 pipeline in PA, NJ, and NY	4-1-92
4.	PennEast CDS	1-15-88	Firm sales and transportation service	147.8	96/4	Service for 13 LDC's in IL, IN, TN, PA, MA, CT, NY, and NJ	11-1-90
5.	Iroquois/ Tennessee	1-17-89 12-29-89	Firm transportation service	645.9	11/89	Service for 17 LDCs, 3 cogenerators and 1 electric generator in NY, NJ, CT, MA, RI, and NH	11-91
6.	Champlain	1-17-89	Firm transportation service	430.6	0/100	Service for 9 LDCs, 8 cogenerators/ electric generators and 1 pipeline in VT, NH, MA and RI	Indefinite
7.	ANR Phase I	2-2-90	Firm transportation service	115.0	100/0	Serve one cogen and one electric utility	11-90 11-91 11-94

NORTHEAST PROJECTS
PENDING

Project	Date Filed	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
8. ANR Phase II	1-17-89 2-2-90 5-23-90 1/	Firm transportation service	388.0	97/3	Service for 19 shippers in NY, NC, MA, MD, PA, RI and NJ	11-90 11-91
9. Indiana-Ohio	1-15-88 8-15-89 5-23-90 1/	Optional to provide transportation service	200.0	Not specified	Not specified	Not specified

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1/ On May 23, 1990, ANR and Trunkline Gas Company (successor in interest to Indiana Ohio) filed a joint amendment of their applications in Docket Nos. CP89-637-002 and CP88-178-002, respectively. Staff has not yet assessed the potential impact of any change in capacity proposed in the joint amendment.

NORTHEAST PROJECTS
PENDING

Project	Date Filed	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
Pending Post Open-Season Filings						
1. CNG	12-28-88	Firm transportation service	25.6	100/0	Service for 3 cogenerators in NY	12-90 5-91 7-92
2. Northern Country Oil Corp. (Falcon Seaboard)	12-8-88	Requests authority to construct border crossing facilities and for Presidential Permit	54.0	0/100	Service for 3 cogenerators in NY	11-1-90
3. Niagara Mohawk	6-5-89	Requests authority to construct border crossing facilities and for Presidential Permit	51.0	0/100	Applicant would import gas for its system supply requirements in NY	11-1-90
4. Empire State	12-4-89	Requests authority to construct border crossing facilities and for Presidential Permit. Gas would move through non-jurisdictional line for consumption wholly in New York	270.0	0/100	Service for LDC and users	Not Stated
5. National Fuel	3-6-90	Proposed facilities would obviate need for part of Empire's non-jurisdictional line. Nat. Fuel also seeks authority for border crossing facilities and Presidential Permit.	267.5	0/100	Seeks to serve Empire's customers as well as 3 separate cogenerators in New York	11-1-91

Table 3

AVAILABLE CAPACITY INTO THE NORTHEAST MARKET AREA AS CERTIFICATED 12/89

PIPELINE COMPANY	PRODUCING REGIONS STATES/CAN	NORTHEAST MARKETS SERVED STATES	ACTUAL NORTHEAST STEADY-STATE CAPACITY (MMCFD)	NORTHEAST FIRM CONTRACT DEMAND(MMCFD
ALGONQUIN	AR, LA, MI, OH, KY, PA, TX, WV, & CAN	CT, MA, NJ, NY, & RI	980.5 1/	980.5
CNG	WV, PA, NY, & LA	NY & PA	1,453.0 2/	1,453.0
COLUMBIA	LA, TX, WY, ND KY, & WV	PA, NY & NJ	676.1 3/	639.5
TENNESSEE	AL, KA, LA, TX, MI, OH, OK, PA, TN, WV, WY, & CAN	CT, MA, NJ, NH, NY, & PA	1,489.1 4/	1,489.1
TETCO	AR, LA, MI OH, KY, PA, TX, WV & CAN	CT, MA, NJ, NY, & PA	3,521.6 5/	3,521.6
TRANSCO	CAN, TX, LA, & MI	NJ, NY & PA	3,323.2 6/	3,239.2

1/ Calculated from Docket No. CP87-554-003

2/ Calculated from Docket No. CP88-712-002

3/ Calculated from Docket No. CP89-1929-000

4/ Calculated from Docket No. CP87-132-001

5/ Calculated from Docket No. CP87-005-003

6/ Calculated from Docket No. CP88-092-001

Northeast Pipeline Peak Day Capacity Utilization

Table 4

Market State	Pipeline	Annual Capacity Utilization 1987	Peak Day Capacity Utilization 1987	Peak Day Capacity Utilization 1989
Connecticut	Tennessee Gas Pipeline	65%	118%	
	Algonquin Gas Transmission	65%	108%	
Massachusetts	Tennessee Gas Pipeline	76%	107%	
	Algonquin Gas Transmission	66%	110%	
New Hampshire	Tennessee Gas Pipeline	57%	110%	
New York	Tennessee Gas Pipeline	68%	109%	
	Algonquin Gas Transmission	68%	107%	
	Transcontinental Gas Pipeline	72%	102%	
	CNG Transmission	31%	84%	
	Columbia Gas Transmission	20%	72%	
	Texas Eastern Transmission	34% (1)	65% (1)	101.5% (2)
New Jersey	Tennessee Gas Pipeline	59%	107%	
	Transcontinental Gas Pipeline	64%	101%	
	Texas Eastern Transmission	40% (1)	67% (1)	101.5% (2)
Rhode Island	Tennessee Gas Pipeline	85%	97%	
	Algonquin Gas Transmission	61%	122%	
Pennsylvania	Tennessee Gas Pipeline	70%	58%	
	Transcontinental Gas Pipeline	99%	102%	
	CNG Transmission	151%	140%	
	Columbia Gas Transmission from Maryland	88%	112%	
	Columbia Gas Transmission from West Virginia	38%	29%	
	Texas Eastern Transmission from Maryland Storage	15%	99%	101.5% (2)
	Texas Eastern Transmission from West Virginia	71% (1)	81% (1)	101.5% (2)

(1) Texas Eastern reported only system sales volumes. Transportation volumes flowing were not reported.

(2) Based on FERC pipeline capacity model and 3 day peak of December 18,19,& 20 1989, reported by Texas Eastern in Docket No. RP90-119-000.

4. Assume that the Commission determines that domestic or foreign natural gas that is (1) decontrolled at the wellhead, (2) targeted to serve U.S. markets, and (3) delivered through interstate or intrastate gas transportation facilities is disadvantaged by a rate design or allocation within the authority of the Commission.

   A. Does the Commission have authority to equilibrate the end price to consumers?

Answer:

If the entities subject to the Commission's jurisdiction are only providing transportation, and not sale for resale, service, no gas costs would be before the Commission upon which it could act and, therefore, the Commission would not have the authority to "equilibrate" the end price to consumers. With regard to sale for resale service, however, the Commission does have authority to adjust rate designs or allocations of jurisdictional costs by pipelines operating in interstate commerce to address competitive disadvantages. It did this in Opinion No. 256, sometimes referred to as the "as billed" decision. In that case, the Commission stated that a U.S. pipeline should recover from its customers the costs it pays for Canadian gas purchased to serve those customers in the same way as it would recover the costs paid for U.S. gas, regardless of how the Canadian exporter may bill the pipeline for the gas costs. Even in this circumstance, however, the Commission would not have authority to "equilibrate" the price to end users since that transaction is outside its jurisdiction.

   B. Does the Commission have the obligation to do so? Under what authorities?

Answer:

If the Commission has the authority to act, it also has the obligation to do so. The Commission is required by the Natural Gas Act to ensure that all rates and charges received by natural gas companies are just and reasonable. This requirement carries with it an obligation for the Commission to eliminate, to the extent possible, unreasonable anti-competitive advantages one source of supply might have over another.

   C. Is this the case even if the Commission's decision is at variance in any regard with any other federal, state, local, or foreign authority?

Answer:

The Department of Energy, Office of Fossil Energy is the office which has been delegated primary authority to approve the import of natural gas. Thus, the Commission may not, in its orders, take actions which are inconsistent with the terms, conditions, or policy considerations reflected in an order authorizing the importation of natural gas issued by the Office of Fossil Energy. In the same vein, the Commission could not issue an order which would run afoul of the Free Trade Agreement's requirement that Canadian gas receive no less favorable treatment than U.S. production, or of other preeminent Federal law. However, as it did in Opinion No. 256, the Commission may prescribe such rate treatments as are necessary to treat domestic and foreign supplies in a similar manner. As long as it is acting on rate design or allocation issues within its authority, the Commission is not bound by potentially contrary state, local or foreign authority.

D. Is the Commission obligated to do so under the Natural Gas Act? Must the Commission consider all factors bearing on the public interest when doing so?

Answer:

As stated above, the Commission is required by the Natural Gas Act to ensure that all rates charged by natural gas companies are just and reasonable. In determining the justness and reasonableness of rates, the Commission must consider all public interest factors, including issues of potential anti-competitive impact.

E. Is the Department of Energy under the same obligations?

Answer:

The Department of Energy is required under section 3 of the Natural Gas Act to determine whether a proposed import of natural gas is in the public interest. In making that determination, it is required to consider the competitiveness of the import, the need for natural gas, and the security of supply. Consideration of rates for transportation or sale for resale of imported gas is within the jurisdiction of the Commission.

F. If negotiations for sales of natural gas are at arm's length between willing buyers and sellers, does the Commission have the authority to examine the end result of the sale to consumers? Does it have the obligation to?

Answer:

The Natural Gas Act gives the Commission authority over the transportation of natural gas in interstate commerce and over the sale in interstate commerce of natural gas for resale for ultimate public consumption. Whether the Commission has the authority and/or obligation to examine the end result of a sale of natural gas to consumers depends on who the sellers and purchasers are. The Commission has the authority and obligation to examine purchases and/or sales of natural gas made by natural gas companies. The Commission has no authority to modify sales agreements between gas purchase customers and suppliers who are outside of its jurisdiction. The Commission does, however, have the authority and obligation to analyze and set reasonable terms and conditions for the transportation of natural gas, bought or sold by non-jurisdictional entities (such as local distribution companies or industrial end users), over jurisdictional facilities, i.e., interstate pipelines. For example, in its recent order authorizing Phase II of the Niagara Import Point Projects (NIPPs II), the Commission maintained the modified-fixed varable rate design for the NIPPs facilities. The result is that the rate design for the transportation of Canadian gas is the same as for the transportation of domestic gas on the Tennesee Gas Pipeline system.

Questions for Chairman Allday

From Senator Bingaman

1. What would constitute an "adequate offer of evidence" to warrant a trial type hearing at the Commission? Could you give me examples of what this type of evidence might be.

Answer:

For any type of evidentiary hearing, there must be an offer of evidence that gives rise to a dispute over an issue of material fact. The evidence must be factual and specific and not merely speculative. A policy argument is not sufficient to bring a factual assertion into question. Additionally, the fact placed in question must be material to the resolution of the matter before the Commission. In many instances, disputes over issues of material fact can be resolved through the presentation of additional documentary evidence, including affidavits, letters, contracts and technical data. The Commission can solicit more information on an issue from any party and/or set an issue for a hearing.

A trial-type hearing may be warranted if the Commission believes the trier of fact will need to see and hear the witnesses in order to determine if they are credible. This is usually not necessary where the issue involves technical information. Where the issue involves a dispute over a past occurrence, credibility of the witnesses may be more relevant in order for the trier of fact to decide which account of the circumstances is credible. For example, where the issue involves an allegation of discriminatory or anticompetitive practices, witnesses may have conflicting accounts of conversations which allegedly took place.

2. In answer to a question from the Committee, Mr. Scherman, the Commission's General Counsel, indicated that full-blown trial type hearings have rarely been ordered in section 7 certificate cases. Why is this the case? How do certificate cases differ in this respect from rate cases under section 4 and 5 of the Natural Gas Act where trial type hearings are frequently ordered?

Answer:

In a certificate case the primary issue is whether a proposed service is required by the public convenience and necessity. Factors that are considered include whether the applicant is willing and able to provide the service, whether the applicant's facilities, proposed or existing, are adequate to provide the service, whether the service is needed, and whether the proposed initial rates are required by the public convenience and necessity. The factual presentation necessary to show that an applicant is able to perform a service is generally not complicated and the evidence is in the form of technical data. Disputes on this issue can often be resolved through the solicitation of more information from the applicant. The market need for a service is also usually shown by the presentation of statistical data, although other parties may dispute the need for the service by providing conflicting data. Resolution of this type of dispute involves analysis of the conflicting data and a reasoned judgment as to what the data shows. Rarely does an issue of this type turn on matters that are most efficiently resolved by cross-examination, such as the personal credibility of a witness.

The rate issues in a certificate case are generally less complex than in a section 4 or 5 proceeding. In a certificate proceeding, only an initial rate is proposed. The rate calculations often are based on predictions of what quantities of natural gas or capacity the applicant will sell and estimates of costs. To the extent there are disputes, they generally involve questions of the appropriate methodology for predicting or estimating sales and costs. Again, this type of dispute can usually be resolved by soliciting more information on paper and rarely turns on the demeanor of a witness. Since the rate approved in a certificate case is only an initial rate, there will be an opportunity for further scrutiny of the methodology involved in a later rate case.

In a rate proceeding under section 4 or 5, trial-type hearings are held more often because the issues are generally more complex and there are often many more issues to resolve than in a certificate proceeding. The types of issues in a rate case are also more susceptible of being resolved through settlement between the parties. This is not the case in a certificate proceeding. For example, whether an applicant is willing and able to perform a service is not the type of issue that the parties can resolve through a settlement.

The prospect of a long and expensive hearing in a rate case often motivates the parties to settle some of the issues in advance of the hearing. When that occurs, fewer issues remain to be resolved at the hearing. A trial type hearing also allows the parties to pursue an issue as it arises. In some cases, rate issues are of the type that evolve as testimony is heard. However, it is important to note that there is nothing inherent in a rate case that requires a trial-type hearing. These proceedings can be, and often are, resolved without a trial-type hearing.

3. Under the Commission's procedural rules, do parties other than the Commission staff have an opportunity for discovery prior to the Commission setting an application for hearing? Have the parties to the Iroquois certificate proceeding (other than Commission staff) had an opportunity for discovery? Isn't the opportunity to take advantage of discovery procedures part of a party's right to a full and fair hearing on the merits?

Answer:

Before a matter is set for a trial-type hearing by the Commission, the parties do not have an opportunity for discovery. Since the Iroquois matter has not been set for a trial-type hearing, there has been no formal discovery in this proceeding to date.

Although the Natural Gas Act requires a hearing before a certificate can be issued, the courts have held that this requirement does not mean that a trial-type hearing is required in every certificate proceeding. If a trial-type hearing is required, because of the nature of the issues or the need to judge witnesses' demeanor, then discovery is appropriate.

Where a trial-type hearing is not required, the parties are provided with other means to state their concerns or to argue to the Commission that additional factual data is needed in order for the Commission to act on the certificate application. These other means assure that all parties have a fair hearing on the merits of an application. For example, in all certificate proceedings, parties may file protests or requests for hearing. In a request for hearing, the party does not have the burden of controverting all facts presented in the application, but rather must show that more information is needed before the Commission can render a decision on the application. The argument in favor of a hearing cannot be based on mere speculation or on policy objections. Generally, a party can make a prima facie showing that an issue needs further exploration without formal discovery.

Based upon its own assessment of the application and the issues raised in protests or requests for hearing, the Commission determines whether additional proceedings are required to resolve issues raised in the proceeding. The

Commission may solicit more information from an applicant. The Commission's rules provide that supplements or amendments to applications must be promptly supplied upon request of anyone who has petitioned to intervene in the proceeding. 18 C.F.R. § 157.10. The Commission can set certain issues for a modified evidentiary hearing, known as a paper hearing, if it believes the issues can be resolved without a trial-type hearing. The Commission may ask the parties, including the applicant, to supply written evidence on issues. The written submissions may take the form of affidavits, testimony, compilations of data or other documentary evidence. The parties then have an opportunity to respond to these written submissions. Formal discovery is not required where the Commission believes the issues may be resolved through a modified hearing process.

In the Iroquois proceeding, the Commission issued numerous data requests, soliciting information from both the project sponsor and its customers. Additionally, in November 1989, a public technical conference was held on Iroquois' proposed rates. At that time, additional comments on the rate issues were solicited from all interested parties.

The Commission also provides an opportunity for the public to raise issues or to submit comments regarding the environmental aspects of a proposal when the Commission believes the proposal may have a significant impact on the environment. In the Iroquois case, for example, scoping meetings were held in the localities through which the proposed pipeline will pass in October, 1987 and April, 1989. The public had an opportunity to bring to the attention of Commission staff issues of concern. Additionally, the public was permitted to comment on the scope of the draft environmental statement during September and October, 1987 and March and April, 1989. After the draft environmental impact statement was issued, the public was again permitted to file comments during the period November, 1989 through February, 1990. Thus, the parties and the public have opportunities to raise relevant issues relating to the environmental aspects of a project and to urge the Commission to obtain more information on specific environmental points.

Questions for Chairman Allday

From Senator Domenici

1. In response to a question about how long trial-type evidentiary hearings take, it was indicated that they could take up to three years to complete, depending on the scope and complexity of the issues subject to the hearing. (Tr. p.37)

   A. Is it possible for FERC to expedite the hearing process by prescribing the issues to be heard, or by directing the ALJ to complete the hearing and issue a decision by a date certain? Has that been done in the past by the Commission?

Answer:

It is possible for FERC to expedite the hearing process by prescribing certain issues to be heard and by directing the ALJ to issue an initial decision by a certain date. The Commission has used this approach on occasion. However, the effectiveness of this approach is limited by the circumstances of each case. More specifically, whether or not a hearing can actually be expedited depends on the nature and complexity of the issues as they appear at the time a hearing is ordered, and on the way the issues evolve in the course of the hearing.

The Commission must balance any attempts to expedite proceedings with due process requirements of all affected parties. If the effort to expedite a hearing results in an incomplete record, then further proceedings may be required. For example, this occurred in a Transcontinental Gas Pipeline case involving rates and conditions for open-access transportation. The Commission severed one issue, related to transition costs and set it for hearing (36 FERC ¶ 61,287 (1986)). In December, 1986, the Commission ordered that an initial decision be issued by February 15, 1987 and ordered an expedited briefing schedule (37 FERC ¶ 61,289 (1986)).

On September 15, 1987, the Commission issued an order affirming the initial decision, in part, and remanding other issues for further hearings (40 FERC ¶ 61,232 (1987)). The Commission found it necessary to order the remand because there was confusion on the part of the parties as to the scope of the hearing and an insufficient record had been developed on certain issues. In that case, attempting to expedite the proceeding further delayed resolution of the case.

I would also note that putting a case on an expedited hearing schedule can interfere with processing the Commission's remaining caseload.

B. The IPAA testified that they want a hearing on only two issues: the rolled-in versus incremental pricing issue which is now before the NEB, and the Iroquois rate structure. (Tr. pp. 98-99) Further, they stated that they do not believe that it would take very long to complete such hearings.

Can you give the Committee an estimate of how quickly such hearings could be completed, assuming for the purpose of analysis that the Commission were to decide to hold them?

Answer:

If the Commission decided to hold trial-type hearings in the Iroquois proceeding, it is difficult to predict with any reliability or certainty how long such hearings would take. There are many factors which can determine the length and scope of the hearing process, such as the complexity and number of the issues, the availability of administrative staff, the size of the record which the ALJ must analyze before issuing an initial decision, as well as unforeseeable delays or postponements requested by the parties.

As indicated in the hearings before the Senate Committee on Energy and Natural Resources on May 3, 1990, the experience of the Commission is that it would not be unusual for a proceeding involving a trial-type hearing to take up to three years to reach a final resolution. However, if a hearing were limited to the issues raised by the IPAA, the proceeding could take less time than if it included issues raised by all of the other parties.

2. Some assert that the U.S.-Canada Free Trade Agreement binds the hands of FERC, preventing it from taking action under the Natural Gas Act to impose such terms and conditions on imports as may be necessary to mitigate anticompetitive or discriminatory aspects.

Senate Report No. 100-509 accompanying the Act which approved and implemented the Agreement makes it perfectly clear that that is not the case. For example, the Report states that:

> Sections 4 and 5 of the Natural Gas Act requires rates and charges for interstate transportation of natural gas to be "just and reasonable". . . and not "unduly discriminatory, or preferential . . . .
>
> * * *
>
> The FERC has authority under the Natural Gas Act to prescribe rules and regulations governing all transportation rates and charges.
>
> * * *
>
> . . . the Agreement does not in any way affect the ability of the U.S. regulatory authorities, including ERA and FERC, to impose appropriate terms and conditions on imports and exports of natural gas under the Natural Gas Act. The Committee sought, and received, assurances that nothing in the Agreement alters, supplants, or preempts the mandate of the natural Gas Act or the Natural Gas Policy Act of 1978.

The Report also goes on at length to make it clear that the Agreement does not affect FERC Opinion No. 256. The Report quotes Canadian Ambassador Gotlieb that "The Canadian Government does not view FERC's as-billed decision as being inconsistent with or affected by the Free Trade Agreement." The Report states that DOE Deputy Secretary Martin concurred in that assessment in testimony before the Committee on Energy and Natural Resources.

Moreover, in written testimony to the Committee FERC Chairman Martha Hesse summed up FERC's understanding of the effect of the Agreement. She stated:

> Inasmuch as the principal statutes under which the Commission operates already mandate nondiscriminatory treatment, the Free Trade Agreement does not in any way alter, supplant, or preempt that mandate. Similarly, since the Commission's policy, consistent with these statutory mandates, is one of nondiscriminatory treatment, we do not foresee any significant alteration or impact on the Commission's decisional process in the future.

Upon review of the Agreement, including the legislative history accompanying it, would not you not agree that the

U.S.-Canada Free Trade Agreement does not prevent the Commission from exercising its authority under the Natural Gas Act and other relevant statutes to insure that gas is not imported under terms or conditions which are discriminatory, anticompetitive or preferential?

Answer:

The U.S.-Canada Free Trade Agreement mandates "national treatment." In the U.S., this means according to natural gas imported from Canada treatment that is no less favorable than the treatment accorded to natural gas produced in the U.S.

The "national treatment" standard is set forth in Article 501 of the Agreement, which incorporates by reference the national treatment standard of Article III of the General Agreement on Tariffs and Trade (GATT). Article 502 applies this standard to states and provinces, as well as to the two federal governments.

Energy is specifically addressed in Chapter Nine of the Agreement. Article 902 reaffirms, for trade in energy goods (identified elsewhere as including petroleum, natural gas, coal, electricity, and uranium and other nuclear fuels), the rights and obligations of both the United States and Canada with respect to prohibitions on import and export restrictions under the GATT. It makes explicit that both countries interpret the GATT to prohibit minimum export price requirements. Article 903 extends the GATT discipline to cover a prohibition on export taxes.

Regulatory approval for the importation of natural gas from Canada falls within the exclusive jurisdiction of the Secretary of Energy. He exercises that authority pursuant to section 3 of the Natural Gas Act. The section 3 authority was transferred to the Secretary by the Department of Energy Organization Act (DOE Act).

As noted in your question, the Commission has the jurisdiction to regulate the transportation, and the sale for resale, in interstate commerce, of Canadian gas within the U.S. after it has been imported. These functions are performed pursuant to sections 4, 5 and 7 of the Natural Gas Act; the DOE Act transferred this authority to the Commission.

Opinion No. 256 involved the classification of costs in the approval of pipeline sales rates, a function that the

Commission performed pursuant to section 4 of the Natural Gas Act. The Secretary of Energy, through his delegatee within the Department of Energy, had already approved the importation of that gas pursuant to section 3 of the Natural Gas Act. In determining the cost classifications for the Canadian gas after it had been imported, the Commission applied the same regulatory standards under section 4 of the Natural Gas Act that it applied to the classification of costs for domestically produced gas.

Thus, the U.S.-Canada Free Trade Agreement does not prevent the Secretary of Energy from exercising his authority to insure that gas is not imported under terms or conditions which are discriminatory, anticompetitive or preferential. The Commission has no statutory authority to regulate the terms and conditions under which the gas is imported. That function is reserved to the Secretary of Energy. If the terms and conditions of the importation are perceived to be discriminatory, anticompetitive or preferential such as to constitute a violation of the Free Trade Agreement (or of other law applicable to trade with Canada), the appropriate procedure under the Agreement would be for the Secretary of Energy and/or the Secretary of State to initiate consultations or negotiations with Canada, or to take some other responsive action.

The Commission is required by both the Agreement and its statutory authority to apply the regulatory standards of the Natural Gas Act in an even-handed, impartial manner regardless of the country of origin of the gas. Any effort by the Commission to impose regulatory treatment on Canadian gas that differs from the treatment accorded to gas of domestic origin would be in derogation of the responsibilities of the Secretary of Energy under section 3 of the Natural Gas Act, and of the Secretaries of State and/or Energy under the Agreement. It would also be in derogation of the Commission's responsibilities under both the Natural Gas Act and the Agreement.

3. The Iroquois project is roughly one-third owned by a Canadian pipeline, one-third owned by U.S. pipelines, and one-third owned by U.S. local distribution companies.

   A. Does the ownership of Iroquois by the upstream pipeline, by potentially competing pipelines, and by the LDCs who receive the bulk of gas moved through Iroquois raise any competitive or discriminatory questions?

Answer:

Whether the ownership structure of Iroquois raises any anticompetitive or discriminatory questions is an issue in the Iroquois proceeding which was raised by the IPAA. The IPAA raised this issue in the initial open-season proceeding in its Comment on Final Report of the Chief Judge and Certification of Settlement filed on December 13, 1988. The IPAA again raised this issue in its Motion for Leave to Intervene, Protest and Request for Formal Hearing filed on February 22, 1989 in the Iroquois proceeding.

Because this issue is under consideration in a matter pending before the Commission, it would be inappropriate to discuss the merits of the issue at this time.

B. Wouldn't an LDC who owns a share of Iroquois have an economic incentive to purchase Iroquois gas rather than gas sold by or transported through another pipeline?

Answer:

As a general matter, an LDC that owns a share of a pipeline might have an economic incentive to purchase gas from that pipeline. In the Iroquois case, however, the issue is not whether an LDC will have an incentive to purchase gas from Iroquois, but whether it will have an incentive to transport gas over the Iroquois system, regardless of the source of the gas. As noted in (A) above, issues relating to the ownership of Iroquois and the effect that may have on competition have been raised in the Iroquois proceeding. It would, therefore, be inappropriate to discuss this matter at this time.

C. Have any state public utility commissions indicated to FERC any concerns about these matters?

Answer:

No state public utility commissions have commented or raised issues regarding the proposed ownership structure of Iroquois.

4. Please summarize Opinion No. 256 and explain the policy it embodies.

Answer:

Opinion No. 256 addressed the issue of the proper ratemaking treatment of Canadian gas costs in the sales rates of domestic pipelines. The main question was whether domestic pipelines could flow through in their rates the Canadian gas costs as billed by the Canadian suppliers.

The "as-billed" rule is included in the Commission's purchased gas adjustment (PGA) regulations. 18 C.F.R. § 154.305(b)(2), in pertinent part, requires that,

> Pipeline supplier rate changes must be applied as-billed to [the downstream] pipeline's two-part rates....

The purpose of the "as-billed" rule is to preserve a rate design which the Commission has found appropriate for a particular pipeline as that pipeline's costs are passed through the rates of downstream pipelines to the ultimate consumer. Hence, under the "as-billed" rule, domestic pipelines include in their demand and commodity charges the demand and commodity charges of their domestic pipeline suppliers exactly as they are billed by the pipeline suppliers.

The Canadian suppliers in general bill the domestic pipelines under a two-part charge. The first is a demand charge which is paid by the domestic pipeline even if it buys no gas. The second is a commodity charge which is a per unit charge paid by the domestic pipeline when it buys gas. The Canadian suppliers assign all of their fixed transmission costs to the demand charge. This is known as the straight fixed variable method of cost classification. In addition, the Canadian suppliers include some wellhead costs in the demand charge. Domestic pipelines have generally used the modified fixed variable method of cost classification under which all fixed transmission costs, other than those associated with return on equity capital and related taxes, have been assigned to the demand charge. Return on equity capital and related taxes and all wellhead costs (production and gathering) are assigned to the commodity charge.

In Opinion No. 256, the Commission disallowed as-billed flowthrough of the Canadian supplier costs and ordered Natural Gas Pipeline Company to reclassify the Canadian supplier costs into Natural's demand and commodity charges under the modified fixed variable method. However, the

Commission did not (as it could not) modify Natural's contractual obligations with its Canadian suppliers. The decision in Opinion No. 256 was necessary so that Canadian gas would be treated no differently from domestic gas in the domestic pipeline's rates. As-billed treatment of Canadian costs would have given a competitive advantage to Canadian gas because domestic pipelines would have been guaranteed recovery, through the demand charge, of more costs paid to Canadian suppliers than they receive for the costs paid to domestic suppliers. Opinion No. 256 created a level playing field. The Commission concluded that its action was not inconsistent with ERA's (now the Office of Fossil Energy, Department of Energy) import authorization and that the as-billed principle did not apply when the Commission has not approved the supplier's methodology. Opinion Nos. 256 and 256-A were affirmed by the U.S. Court of Appeals for the District of Columbia Circuit in TransCanada PipeLines Ltd. v. FERC, 878 F.2d 401 (D.C. Cir. 1989).

A. As a matter of policy, should the principles of Opinion No. 256 be applied to transportation gas? If not, wouldn't that create an enormous loophole for importing pipelines to escape the application of Opinion No. 256 simply by moving the point of sale outside of the U.S. and having only the transportation of such gas occur in the U.S.? If the principles of Opinion No. 256 are not applied to transportation gas, wouldn't that enable Canadian gas to gain an unfair advantage, which was the original problem which led the Commission to issuing Opinion No. 256?

Answer:

As a matter of policy, the cardinal principle of Opinion No. 256, that foreign and domestic gas should compete on a level playing field with respect to marketing gas in the United States, should apply to foreign gas transported by a domestic pipeline as well as to foreign gas sold by a domestic pipeline. If this principle is not applied to the transportation of foreign gas, Canadian gas could gain a competitive advantage over domestic gas if the interstate pipeline provides only transportation, but not sale for resale, service.

The question of whether the objective of comparable treatment for Canadian and domestic gas supplies could be achieved unless all importers of natural gas, including local distribution companies and other entities not subject to the Commission's jurisdiction, are subject to the same constraints was raised on rehearing of Opinion No. 256.

The Commission has no authority to modify the sales agreements between gas purchase customers and suppliers who are outside of our jurisdiction. An attempt by the Commission to do so (by, for example, imposing Opinion 256-type restrictions on such agreements) could be seen, depending on the circumstances, as an improper attempt to intrude upon the jurisdiction of state regulatory authorities, which would have jurisdiction over LDC customers, and/or of any Canadian regulatory authorities with jurisdiction over the Canadian producers and Canadian pipelines. Furthermore, such action would impinge upon the jurisdiction and authority of the DOE Office of Fossil Energy, which grants import authorization upon a finding that such transactions are consistent with the public interest.

Despite these limitations on the jurisdiction of the Commission, the Commission has taken steps to level the competitive playing field. For example, in its order on Phase II of Niagara Import Point projects, the Commission conditioned its authorization of transportation of Canadian gas to require that the pipeline companies adopt a rate design methodology which made the playing field for domestic and Canadian producers more level than it would have been under the methodology proposed by the pipelines. The rate design for transportation rates within the United States is thus the same for both Canadian and domestic gas.

B. Does the Commission have the authority to prevent a pipeline's sales transaction which is currently subject to Opinion No. 256 from being reformulated into a transportation only transaction, to which Opinion No. 256 does not now apply?

Answer:

If the pipeline wanted to convert an existing sales transaction to a transportation only transaction, it would have to apply to the Commission for abandonment authority under section 7(b) of the Natural Gas Act, which the Commission could grant or deny.

C. Please provide the Committee a copy of the March 30, 1990 OGC memorandum Options For Addressing Rate Design

Issues in Natural Gas Pipeline Construction Projects Involving Imported (Canadian) Natural Gas.

Answer:

The memorandum is predecisional and subject to attorney-client privilege. It is, therefore, protected from normal disclosure. One copy of the memorandum is being provided under separate cover and I request that you treat this document as privileged and not subject to disclosure or release.

5. The National Energy Board of Canada is currently considering whether the $2.6 billion costs of TransCanada's proposed expansion should be "rolled-in" or "incrementally" priced. Obviously, the costs of transportation across Canada and how they are to be allocated will materially affect the issues of unfair competition and discrimination raised by U.S. producers. And it will affect the ultimate consumers of the gas, as well as the financial viability of the Iroquois project.

Can the Commission act on the Iroquois certificate before this process is completed in Canada?

Answer:

Yes. The Iroquois project currently proposes to offer only transportation within the United States. TransCanada costs, on the other hand, comprise part of the gas purchase costs and are not part of the transportation costs before the Commission in Iroquois' application.

However, the possible impact of the National Energy Board's actions on that issue will be considered by the Commission in determining whether the Iroquois project has been shown to be required for the convenience and necessity of the public. Depending on what the evidence shows, the Commission can either deny Iroquois' application or condition any certificate which it issues to ensure that the public interest is protected. As this is an issue in a pending case before the Commission, I cannot comment on it further.

However, in its recent decision regarding Phase II of the Niagara Import Point projects, the Commission conditioned the certificates granted therein to (1) prohibit the commencement of construction until such time as final, long-term export licenses were issued by the NEB or, at the option of the applicants, (2) place the applicants at risk (by prohibiting any shifting of costs associated with the proposals onto other customers) for any shortfall in cost recovery experienced as a result of the projects failing to receive long-term export authority.

6. Please provide the Committee a list of all applications filed pursuant to the "Northeast open season", a brief summary of the proposed projects, and the current status of the applications. Please indicate which of these proposed to bring domestic gas to the Northeast market, and which proposed to bring Canadian gas.

Answer:

Attached are two tables listing Northeast-related projects. The first table (Table 1, pages 1 through 4) lists the applications filed with the Commission, grouped by project. The second table (Table 2, pages 1 through 5) shows the status and a brief summary of each project. The summary table separates the projects into three groups -- the approved projects (20 projects), the pending projects (9 projects), and those projects filed after the open season process had ended (5 projects). Domestic gas represents about 56 percent by volume of all of the Northeast projects compared to about 44 percent from Canada. These figures do not include the Champlain project, which is being held in abeyance at the applicant's request. If all of the pending projects are approved through the 1990's domestic gas would serve over 80 percent of the aggregate demand in the Northeast.

7. Please describe the differences between Canadian and U.S. rate design. Are the differences between the way rates are established the source of any competitive advantage? Are these differences being addressed through the implementation of the Commission's May 30, 1989 rate design policy statement?

Answer:

Canadian transportation rates reflect the so-called Straight Fixed Variable (SFV) rate design methodology whereas most U.S. pipelines now employ the Modified Fixed Variable (MFV) methodology. These methodologies both involve the use of demand and commodity charges. The demand charge is billed on the basis of the customer's maximum daily contractual entitlement, or Contract Demand, and the commodity charge is billed on the basis of the actual quantity moved for the customer. Thus, the demand charge is a fixed charge each month and does not vary with the customer's actual utilization of the system.

Under the SFV methodology, the pipeline recovers all of its fixed costs, i.e., those that don't vary with throughput, in its demand charge and all of its variable costs, i.e., those that vary directly with throughput, in its commodity charge.

By contrast, under MFV, all fixed costs, with the exception of return on equity capital and related income taxes, are recovered in the demand charge whereas return on equity and related taxes, together with all variable costs, are recovered in the commodity charge.

Assuming a customer has already contracted for service on both a Canadian and a United States pipeline, and assuming all other things being equal, a customer would likely utilize the service of the SFV pipeline. This stems from the fact that the marginal cost of transporting gas on the SFV pipeline is less than on the MFV pipeline, owing to the SFV pipeline's lower commodity charge for identical service. However, all other things are rarely equal. For example, on May 2, 1990 the Commission considered the competitive effect of Canadian rate design on customers' purchases in the Phase II Niagara Import Point project proceeding. The Commission noted that comparing the total aggregate commodity charge of the Phase II imports, as conditioned in the order, with alternative domestic service resulted in Canadian commodity charges higher than, or equal to domestic service.

Although the differences in U.S. and Canadian regulatory policies were not specifically addressed in the Commission's rate design policy statement, the general issue of competition and efficiency is central to the proceedings being conducted under the policy statement. In its May 2, 1990 order in the Phase II Niagara Import Point project proceeding the Commission noted that: "If IPAA or others raise the issue of a potential anticompetitive preference for Canadian versus domestic gas supply in those proceedings, all interested parties, Commission trial staff, and the ALJ's will have the opportunity to throroughly examine the issue and devise and consider appropriate and effective solutions which will ensure that both sales and transportation of Canadian and U.S. domestic gas are treated in a fair and nondiscriminatory manner." (Tennessee Gas Pipeline Company, et al., Docket Nos. CP88-171-000, et al., 51 FERC ¶ 61,113, slip op. at pp. 34-35.) Also, in the rate design policy statement, the Commission expressed its concern that the MFV rate design may be outdated in light of the significant changes in the natural gas pipeline industry since 1985.

8. As currently proposed, the Iroquois project would bring 352 million cubic feet per day of gas to the U.S., however the Iroquois project has no compression.

   a. If compression stations are added, by how much could Iroquois throughput be increased?

Answer:

As currently proposed to the Commission, the Iroquois project (without Tennessee's additional capacity) would have a capacity without compression approximating 576 million cubic feet per day (MMcf/d). If compression were added, throughput could be increased by anywhere from 176 MMcf/d to 500 MMcf/d. The lower figure assumes a minimal compressor upgrade of 16,750 horsepower, while the higher figure assumes five compressor stations with a total of 118,324 horsepower. However, an Iroquois upgrade using five compressor stations totaling 118,324 hoursepower might not be economic, because of the incremental cost of fuel, when compared to an expansion design including both compression and looping. It should also be noted that expansion of Iroquois capacity would also necessitate additional capacity expansion on other downstream systems (Tennessee, Algonquin and possibly others) to effectuate delivery.

   b. Has the Commission considered this question when reviewing the Iroquois certificate?

Answer:

The Commission reviews the design of proposed facilities for each project. This review focuses on whether the proposed facilities are adequate -- neither larger nor smaller than required -- to provide the service proposed. An applicant often may choose between building a bigger pipe or a smaller pipe with compression to achieve the same design capacity. In most cases the choice will be an economic one. If the alternative costs are approximately the same most applicants will choose to build a bigger pipe. Use of a bigger pipe allows for future expansion through the addition of compressor stations, which may be an environmentally preferred alternative, in at least some cases, to the construction of pipeline looping.

c. Could Iroquois add compression stations using NGPA section 311 authority, or would that require an amendment to their certificate?

Answer:

Facilities constructed pursuant to NGPA Section 311 authority may be used only for the delivery of gas transported pursuant to NGPA Section 311. In any case where the gas to be delivered includes a commingled flow of gas transported pursuant to Section 7 NGA authority, Iroquois would be unable to meet that test. The addition of compression on the Iroquois pipeline would require an amendment to its certificate.

NORTHEAST PROJECTS

Table 1
Page 1

Project	Docket No. - Company
1. DOMAC Excess LNG (Issued 3-21-88)	CP88-160-000 Distrigas CP88-161-000 Distrigas
2. Commonwealth (Issued 6-29-88)	CP87-492-000 Algonquin
3. Niagara Spur I (Issued 6-30-88)	CP87-131-000 Tennessee CP87-131-001 Tennessee
4. CNG Storage (Issued 7-27-88)	CP87-447-000 CNG
5. PennEast Sales (Issued 7-27-88)	CP87-4-000 PennEast CP87-4-001 PennEast/TETCO CP87-4-002 PennEast/TETCO CP87-5-000 CNG CP87-28-000 TETCO CP87-28-002 TETCO
6. ORU (Issued 7-27-88)	CP87-339-000 Columbia
7. Biddlecum Road (Issued 7-27-88)	CP86-344-000 CNG
8. Beverly Salem (Issued 9-16-88)	CP87-85-000 Tennessee
9. New Jersey/Providence Replacement (Issued 9-16-88)	CP88-164-000 Columbia
10. Niagara Spur II (Issued 10-3-88)	CP87-131-000 Tennessee CP87-131-001 Tennessee
11. Ocean State (Issued 10-3-88)	CP87-132-000 Tennessee CP87-132-001 Tennessee
12. Braintree (Issued 5-18-89)	CP88-167-000 Algonquin
13. NOREX (Issued 5-18-89)	CP87-358-000 Tennessee CP87-358-001 Tennessee CP87-428-000 CNG CP87-428-001 CNG
14. New Jersey/Providence (Issued 7-17-89)	CP88-129-000 Columbia CP88-129-001 Columbia CP88-163-000 Columbia

NORTHEAST PROJECTS

Table 1
Page 2

Project	Docket No. - Company
15. Providence (Issued 5-18-89)	CP87-75-000 Tennessee
16. APEC I (Issued 6-7-89)	CP87-5-003 TETCO/CNG
	CP87-92-003 TETCO/CNG
	CP87-312-002 TETCO/CNG
	CP87-197-001 TETCO/CNG
	CP88-388-001 TETCO/CNG
17. APEC II/III (Issued 6-7-89)	CP87-5-002 CNG
	CP87-312-001 CNG
	CP87-313-001 CNG
	CP87-314-001 CNG
	CP87-554-001 Algonquin
	CP88-197-002 CNG
	CP88-388-002 CNG
	CP89-6-000 Transco
18. Niagara Import Point Phase I (SS-2) (Issued 7-27-89)	CP88-194-000 National Fuel Penn-York
	CP88-194-001 National Fuel Penn-York
	CP89-7-000 Transco
	CP89-7-001 Transco
	CP88-195-000 PennEast/CNG TETCO
	CP88-195-001 PennEast/CNG TETCO
	CP88-195-002 PennEast/CNG TETCO

NORTHEAST PROJECTS

Table 1
Page 3

Project	Docket No. - Company	
19. Niagara Import Point Phase II (Issued 5-2-90)	CP88-92-000	Transco
	CP88-92-001	Transco
	CP88-94-000	National Fuel
	CP88-94-001	National Fuel
	CP88-171-000	Tennessee
	CP88-171-001	Tennessee
	CP88-194-000	National Fuel Penn-York
	CP88-194-001	National Fuel Penn-York
	CP88-195-000	PennEast/CNG TETCO
	CP88-195-001	PennEast/CNG TETCO
	CP88-195-002	PennEast/CNG TETCO
	CP88-195-005	PennEast/CNG TETCO
20. APEC IV (Approved 5-30-90)	CP87-5-002	CNG
	CP87-312-001	CNG
	CP87-312-004	TETCO
	CP87-312-006	TETCO
	CP87-313-001	CNG
	CP87-314-001	CNG
	CP87-554-001	Algonquin
	CP88-197-002	CNG
	CP88-388-002	CNG
21. Niagara Import Point Phase III	CP88-171-001	Tennessee
	CP88-187-001	Algonquin
	CP88-194-001	National Fuel Penn-York
	CP88-195-002	PennEast/CNG TETCO
	CP89-7-001	Transco
	CP89-710-000	Transco
	CP89-711-000	TETCO
	CP89-712-000	CNG
	CP89-892-000	Great Lakes
22. Public Service	CP88-172-000	Tennessee
23. CRP/LNG Reinstatement	CP87-94-004	TETCO

NORTHEAST PROJECTS

Table 1
Page 4

Project	Docket No. - Company
24. PennEast CDS	CP88-180-000 TETCO
	CP88-180-002 TETCO
	CP88-185-000 Algonquin
	CP88-185-002 Algonquin
25. Iroquois/Tennessee	CP89-634-000 Iroquois
	CP89-634-001 Iroquois
	CP89-815-000 Iroquois
	CP89-629-000 Tennessee
	CP89-629-001 Tennessee
	CP90-639-000 Tennessee
	CP89-661-000 Algonquin
	CP89-661-001 Algonquin
	CP89-1263-000 TETCO
	CP89-1339-000 BUG, ConEd & LILCO
26. Champlain	CP89-646-000 Champlain
	CP89-654-000 Champlain
	CP89-661-000 Algonquin
27. ANR	CP89-637-000 ANR
	CP89-637-001 ANR
	CP89-637-002 ANR
	CP89-635-000 Columbia
	CP89-635-001 Columbia
	CP89-638-000 CNG
	CP89-638-001 CNG
	CP89-661-000 Algonquin
	CP89-661-001 Algonquin
	CP90-687-000 Transco
	CP90-688-000 Texas Gas
28. Indiana-Ohio	CP88-178-000 Indiana-Ohio
	CP88-178-002

Table 2
Page 1

NORTHEAST PROJECTS
APPROVED

Project	Date Issued or Approved	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
1. ORU	7-27-88	Increase existing contract demand sales	1.2	100/0	Service for NY LDC (local distribution company	Not Applicable
2. Biddlecum Rd	7-27-88	Increase in firm sales	44.2	100/0	"	"
3. Commonwealth	6-29-88	Firm 20-year transportation for peak day use	40.0	100/0	Service for MA LDC	"
4. PennEast Sales	7-27-88	Firm transportation and sales from system supply, storage service	123.0	96/4	Transportation for 5 LDC's in NY and NJ and storage for 1 other LDC	"
5. Beverly-Salem	9-16-88	Pipe replacement to firm-up previously authorized transportation service	10.5	0/100	Service for MA LDC	"
6. Niagara Spur I	6-30-88	System supply capacity expansion	40.0	0/100	Existing customers and market	"
7. Niagara Spur II	10-3-88	System supply capacity expansion	110.0	0/100	"	"
8. CNG Storage	7-27-88	Firm storage service	80.0	96/4	Storage service by CNG for Tennessee	"
9. DOMAC LNG	7-21-88	Sale of LNG for peaking purposes	150.0	Imported LNG	Northeast customers	"
10. NJ/Providence Replacement	9-16-88	Replacement of existing mainline facilities to restore capacity	59.7	----	Existing customers and market	"
11. Ocean State	10-3-88	Firm 20-year transportation service	50.0	0/100	Electric generation facility in RI	"
12. Braintree	5-18-89	Firm 20-year transportation service	21.7	92/8	Electric generation facility in MA	Not Applicable

NORTHEAST PROJECTS
APPROVED

Project	Date Issued or Approved	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
13. Norex	5-18-89	Firm sales increase and transportation service	91.4	96/4	10 existing LDC's in MA, NH, CT and RI	"
14. Providence	5-18-89	12-year sales service	30.0	96/4	Service for LDC in RI	"
15. APEC I	6-7-89	Restore certificated capacity on Texas Eastern's system	554.3	100/0	Provides capacity for CNG under APEC II/III below	"
16. APEC II/III	6-7-89	Provide transportation, storage or sales service	395.0	100/0	Storage for 11 LDC's and 2 cogenerators in RI, NY, MA, PA and CT. Sales to 11 LDC's by CNG, with Transportation by Transco, Algonquin and Texas Eastern.	"
17. APEC IV	5-30-90	Transportation and storage service	99.1	100/0	Service for 6 LDC's in MA, NJ, PA, and NY	4-1-91
18. NJ/Providence	7-17-89	Provide sales and transportation	80.0	100/0	Sales to 2 LDC's in NJ and RI and transportation of gas to them	"
19. NIPS (SS-2)	7-27-89	Provide storage service for 11 Bcf and related storage transportation of 100 MMcf/d	100.0	93/7	Services provided for 6 LDC's and 2 cogenerators in NY, NJ and PA	"
20. NIPS II	5-2-90	Firm transportation service	132.2	19/81	Service for 3 LDC's and 4 cogenerators in CT, MA, MD, NJ and NY	"

Table 2
Page 3

NORTHEAST PROJECTS
PENDING

Project	Date Filed	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
1. NIPS III	1-15-88	Firm transportation service	360.4	7/93	Service for 3 LDCs, 9 cogenerators and 1 electric generator and 2 pipelines in NY, NJ, PA, MA, RI, and VA	11-90
2. Public Service	1-15-88	Firm sales service	40.0	96/4	Service for an LDC in NJ	11-91
3. CRP/LNG Replacement	11-10-88	Restoration of capacity	102.1	----	Service for 5 LDC's and 1 pipeline in PA, NJ, and NY	4-1-92
4. PennEast CDS	1-15-88	Firm sales and transportation service	147.8	96/4	Service for 13 LDC's in IL, IN, TN, PA, MA, CT, NY, and NJ	11-1-90
5. Iroquois/ Tennessee	1-17-89 12-29-89	Firm transportation service	645.9	11/89	Service for 17 LDCs, 3 cogenerators and 1 electric generator in NY, NJ, CT, MA, RI, and NH	11-91
6. Champlain	1-17-89	Firm transportation service	430.6	0/100	Service for 9 LDCs, 8 cogenerators/ electric generators and 1 pipeline in VT, NH, MA and RI	Indefinite
7. ANR Phase I	2-2-90	Firm transportation service	115.0	100/0	Serve one cogen and one electric utility	11-90 11-91 11-94

Table 2
Page 4

NORTHEAST PROJECTS
PENDING

Project	Date Filed	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
8. ANR Phase II	1-17-89 2-2-90 5-23-90 1/	Firm transportation service	388.0	97/3	Service for 19 shippers in NY, NC, MA, MD, PA, RI and NJ	11-90 11-91
9. Indiana-Ohio	1-15-88 8-15-89 5-23-90 1/	Optional to provide transportation service	200.0	Not specified	Not specified	Not specified

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1/ On May 23, 1990, ANR and Trunkline Gas Company (successor in interest to Indiana Ohio) filed a joint amendment of their applications in Docket Nos. CP89-637-002 and CP88-178-002, respectively. Staff has not yet assessed the potential impact of any change in capacity proposed in the joint amendment.

Table 2
Page 5

NORTHEAST PROJECTS
PENDING

Project	Date Filed	Summary of Project	Service (MMcf/d)	Gas Source % U.S./Canadian	Markets To Be Served	Proposed In Service Date
Pending Post Open-Season Filings						
1. CNG	12-28-88	Firm transportation service	25.6	100/0	Service for 3 cogenerators in NY	12-90 5-91 7-92
2. Northern Country Oil Corp. (Falcon Seaboard)	12-8-88	Requests authority to construct border crossing facilities and for Presidential Permit	54.0	0/100	Service for 3 cogenerators in NY	11-1-90
3. Niagara Mohawk	6-5-89	Requests authority to construct border crossing facilities and for Presidential Permit	51.0	0/100	Applicant would import gas for its system supply requirements in NY	11-1-90
4. Empire State	12-4-89	Requests authority to construct border crossing facilities and for Presidential Permit. Gas would move through non-jurisdictional line for consumption wholly in New York	270.0	0/100	Service for LDC and users	Not Stated
5. National Fuel	3-6-90	Proposed facilities would obviate need for part of Empire's non-jurisdictional line. Nat. Fuel also seeks authority for border crossing facilities and Presidential Permit.	267.5	0/100	Seeks to serve Empire's customers as well as 3 seperate cogenerators in New York	11-1-91

Department of Energy
Washington, DC 20585

July 24, 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

On May 3, 1990, Mark Schroeder, Deputy General Counsel for Environment, Conservation and Legislation gave testimony before your committee on the importation of natural gas into the United States.

Following that hearing, you submitted written questions on behalf of yourself, Senator Pete V. Domenici, and Senator Jeff Bingaman to supplement the record.

Enclosed are the answers to those questions, which also have been sent to Senators Domenici and Bingaman.

If you have any questions, please have your staff call Renee Wilhite on 586-4277. She will be happy to assist you.

Sincerely,

Jacqueline Knox Brown

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental Affairs

Enclosure

QUESTIONS FROM SENATOR JOHNSTON

Question 1:	In your testimony you indicate that Opinion and Order No. 368 is not a final order due to the Department's obligations under the National Environmental Policy Act (NEPA). A. How might the Department's compliance with its procedural obligations under NEPA affect the Department's decision to authorize imports of natural gas under section 3 of the Natural Gas Act?
Answer:	NEPA requires the Department to consider the environmental effect of this and all major actions proposed by the agency which may significantly affect the quality of the environment. Consistent with this obligation, the Department cannot make a final decision until the necessary environmental review has been completed. In this particular case, FERC has the lead in preparing an EIS on related new transportation facilities. The Department is a cooperating agency with FERC and once the EIS is completed DOE will issue a Record of Decision as required by 40 CFR Sec. 1505.2. It would be inappropriate at this time to speculate on how this process might affect the final decision.

QUESTIONS FROM SENATOR JOHNSTON

B. In terms of the factors considered and the criteria applied, what is the relation between the Department's application of its import guidelines under section 3 of the Natural Gas Act and the Department's NEPA obligations?

Answer: Application of the Department's natural gas import guidelines and its NEPA obligations are separate but related processes. The NEPA process must be complete before any final decision is made under section 3 of the Natural Gas Act. In making this final decision the Department will consider whether the results of the environmental review, including identified environmental impacts and suggested mitigation measures, affect the public interest determination being made under section 3 of the Natural Gas Act.

C. What flexibility does the Department retain to modify its preliminary findings under section 3 of the Natural Gas Act in light of its fulfillment of its procedural obligations under NEPA? What factors might persuade the Department to modify its preliminary findings under section 3?

Answer: The Department retains full flexibility to modify its preliminary findings based on a reexamination of those findings at the time of DOE's review of the final EIS. Since the EIS focuses on environmental issues, any modifications are most likely to reflect environmental considerations related to the proposed action.

QUESTIONS FROM SENATOR JOHNSTON

Question 2: In response to a question, you indicated that you would provide the Committee with information regarding instances where the Department has denied applications to import Canadian natural gas. In providing such information:

A. Please describe the circumstances of the case and the reason for the Department's decision to deny authorization under section 3 of the Natural Gas Act;

B. Please indicate whether the denial occurred under the existing natural gas import guidelines or under earlier guidelines; and

C. Please also identify and describe instances where the Department has conditioned its authorization to incorporate terms and conditions other than those proposed by the applicant.

Answer: Prior to issuance of the 1984 policy guidelines, the Department denied Northern Natural Gas Company and Great Lakes Gas Transmission Company authority to import synthetic natural gas from Canada by displacement. 1 ERA Para. 70,503 (March 8, 1979). The Department said the applicants had not demonstrated regional or national need for what the agency considered a costly marginal gas supply. In 1980 DOE denied separate applications filed by Montana Power Company, Columbia Gas Transmission Company, and Northern Natural Gas Company for long-term authority to import new volumes of Canadian natural gas for system supply. In all three cases, addressed in a consolidated order, the applications were denied because DOE found the uniform border price set by Canada at the time was not competitive with residual fuel oil and largely on this basis concluded there had not been a showing of compelling immediate need for the supplies. 1 ERA Para. 70,502 (February 16, 1980).

Since 1984, applicants, as anticipated, have followed the "road map" provided by the policy guidelines. DOE routinely imposes conditions on authorizations. For example, blanket authorizations are generally limited to a maximum term of two years and are subject to a stringent, transaction-by-transaction after-the-fact reporting requirement. In another case-specific example, in Pan National Gas Sales Inc., 1 ERA Para. 70,133 (December 23, 1988), DOE conditioned Pan National's 20-year authorization to import Algerian LNG to require separate application for domestic sales involving contractual commitments longer than two years. DOE also ordered a shorter period for reporting sales transactions than the period proposed by Pan National. More often, where applications have not conformed to the guidelines or where there has been some question, DOE has requested additional information (for example, an interlocutory procedural order requested supplemental information on both supply security and need in Granite State Gas Transmission Inc., 1 ERA Para. 70,717). Applicants have responded to correct any deficiencies and/or to supply additional information,

QUESTIONS FROM SENATOR JOHNSTON

or they have withdrawn their application (for example, in Kern River Gas Supply Corporation, Docket No. 86-12-NG, the applicant withdrew after DOE issued an order proposing to deny the application for long-term import authority which was not supported by contracts).

QUESTIONS FROM SENATOR JOHNSTON

Question 3: DOE's import policy guidelines are pretty vague. As you indicated in your testimony, competitiveness is the primary criteria and if that is established, need and supply security are presumed.

A. Has anybody ever been successful in rebutting these presumptions?

Answer: The 1984 policy guidelines defined the public interest in favor of market-oriented considerations and announced two primary, rebuttable presumptions: first, that an import contract would be presumed competitive if its terms provided the importer with sufficient flexibility to respond to changing market conditions; and second, since "(n)eed for a gas supply is intrinsically related to its anticipated marketability," a competitive import would be presumed needed.

Those seeking import authority have responded to the clear direction provided by the policy guidelines to negotiate market-responsive arrangements that have benefitted consumers. Parties opposing applications have been unsuccessful in rebutting presumptions because they failed to demonstrate the import proposals were not sufficiently flexible to protect the importer from changing market conditions.

QUESTIONS FROM SENATOR JOHNSTON

B. How is the Department's analysis adjusted, depending upon the type of import arrangement proposed? For example, the difference between a short-term deal to sell spot market gas and a long-term deal involving significant volumes.

Answer: While the Department considers the same basic factors, in neither case does the Department believe that market-responsive arrangements are facilitated by a uniform regulatory approach. Terms and conditions of an arrangement that are competitive in one market or under one set of circumstances may not be competitive in another. The duration of an import, as you suggest, affects the manner in which the Department applies the policy criteria. Shorter-term arrangements are inherently more flexible, and security of supply is less significant. Longer-term arrangements, by contrast, generally involve greater tension between flexibility and supply commitment, and the Department considers the necessary balancing that must be achieved between those forces.

QUESTIONS FROM SENATOR JOHNSTON

Question 4: In Opinion and Order No. 368, the Office of Fossil Energy states at page 26: "A DOE finding that an import is not inconsistent with the public interest subsumes a finding of prudence. However, this finding is not meant to preclude state agencies from setting appropriate rates for entities they regulate."

A. Has this statement of DOE's understanding of the law been included in any earlier orders authorizing imports of natural gas? Has this statement of the law been challenged on judicial review or otherwise upheld by the courts?

Answer: The Department has addressed the prudency issue similarly in a number of earlier orders in response to arguments of domestic producers that jurisdiction to evaluate the prudence of purchasing imported gas rests not with the Department but with FERC and/or any applicable state regulatory agency. See Entrade Corporation, 1 ERA Para. 70,774 (May 5, 1988), Alenco Resources Inc., 1 ERA Para. 70,808 (August 31, 1988), Northern Natural Gas Company, 1 ERA Para. 70,812 (September 16, 1988), and Tennessee Gas Pipeline Company, 1 ERA Para. 70,836 (January 18, 1989). None of these cases was litigated. However, in its June 1989 decision affirming FERC Order 256, the D.C. Circuit Court of Appeals also upheld FERC's decision declining to review for prudence gas import contracts already approved by DOE. TransCanada Pipelines Limited v. FERC, No. 87-1229, slip. op. The court specifically found DOE's interpretation of prudence in the unrelated Entrade case to be reasonable.

QUESTIONS FROM SENATOR JOHNSTON

B. What does it mean to say that a finding of prudence is subsumed? In particular, in what areas does the finding preempt state regulatory authorities?

Answer: The Department presumes the terms of an import arrangement found to be consistent with the public interest are prudent, and has offered the following rationale, quoted by the D.C. Circuit in TransCanada, slip. op. at 11.

> Although the ERA has not made an explicit prudency finding in approving imports under Section 3 of the NGA, a determination that an import arrangement is not inconsistent with the public interest reflects consideration of matters relevant to the prudency of that arrangement and necessarily subsumes a finding that an import is not imprudent. EnTrade Corporation, 1 ERA Para. 70,774, at 72,887 (1988).

In general, it is the policy of the Department that state agencies are in the same position as FERC and should not regulate in a manner inconsistent with DOE's regulation.

C. When DOE issues an order authorizing natural gas imports, what legal effect does this have on the ability of state public utility commissions to regulate local distribution companies' recovery of the cost of the imported gas?

Answer: State public utility commissions are constrained to act consistently with determinations contained in DOE import orders, including the recovery of costs approved by the Department. The Department pays particular attention to the concerns of local regulatory authorities and if they have doubts about whether an import is in the public interest, they are encouraged to participate in the DOE proceeding.

QUESTIONS FROM SENATOR JOHNSTON

Question 5: In answer to a question from the Committee, you indicated that the Department's natural gas import policy has been upheld by at least two different U.S. Circuit Courts of Appeal.

A. Please identify and describe these cases. In particular, please describe the facts of the import authorization that were the subject of the challenge and the legal issues adjudicated by the courts.

B. Did any of these cases involve authorization of a long-term import arrangement involving substantial volumes of natural gas such as the arrangement conditionally authorized in Opinion and Order No. 368?

Answer: Four of the six DOE/ERA suits described below were brought by domestic producers, and three of the six involved long-term import arrangements.

(1) In Panhandle Producers and Royalty Owners Association v. ERA, 822 F.2d 1105 (D.C. Cir. 1987), petitioner challenged an ERA order granting a wholly-owned subsidiary (Northridge Petroleum Marketing U.S. Inc., 1 ERA Para. 70,605) of a Canadian corporation blanket authority to import limited quantities of gas from Canada over a two-year period. Petitioner sought review on three bases, arguing first that ERA had relied improperly on the policy statement, which was not issued in accordance with formal rule-making procedures, and therefore could not be treated as a substantive rule. Second, petitioner argued that the policy statement and ERA's application of the policy in its decision improperly placed the burden of proof on petitioner and failed to consider factors which

had been relevant under prior DOE policy and delegation orders. Third, the petitioner contended that it was entitled to a trial-type hearing.

The D.C. Circuit rejected all of petitioner's procedural and substantive arguments, holding that ERA did not err in relying on the policy statement and the presumptions created by it, that the petitioner was not entitled to a trial-type hearing, and that placing the burden on the opponent was consistent with section 3 of the NGA which "requires an affirmative showing of inconsistency with the public interest to deny an application." The court found that ERA had made appropriate findings based on substantial evidence, including the presumptions, and concluded that the petitioner's issues were largely ones of policy and did not provide sufficient evidence to put "material issues of fact genuinely in dispute."

(2) A year later, in Panhandle Producers & Royalty Owners Association (PPROA) v. ERA, 847 F.2d 1168 (5th Cir. 1988), the Fifth Circuit rejected substantially identical objections to ERA reliance on the policy guidelines raised by the PPROA in three similar, short-term blanket import authorizations. Tennessee Gas Pipeline Co., 1 ERA Para. 70,674; Western Gas Marketing U.S.A., Ltd., 1 ERA Para. 70,675; Enron Gas Marketing Inc., 1 ERA Para. 70,676. In

addition, the court found substantial evidence in the record to support ERA's refusal to impose the PPROA's requested "open-access" requirement (i.e., that all domestic pipelines, including those downstream pipelines participating in the import, be open-access) and other conditions requested by PPROA and to support ERA's decision that an environmental assessment was not necessary.

(3) Independent Petroleum Association of America (IPAA) v. ERA, 870 F.2d 168 (5th Cir. 1989). In an originally unpublished decision issued on March 15, 1989, the Fifth Circuit rejected, this time in the context of an extension of long-term authority to import up to 75,000 Mcf per day held by Texas Eastern Transmission Corporation, 1 ERA Para. 70,733, the same arguments made previously by PPROA relating to the 1984 policy guidelines, and to compliance by ERA with its own regulations and NEPA. Further, the Court upheld ERA's denial of conditions, requested by IPAA, which would have mandated "open-access" and eliminated the imported gas volumes two-part rate. The court found petitioner's attempts to distinguish the short-term, blanket Panhandle case on factual and procedural grounds unpersuasive.

This was one of numerous ERA proceedings where IPAA submitted "expert testimony" to rebut the presumptions of competitiveness and need. In general, this testimony has relied on matters either unsupported by any evidence or irrelevant under DOE policy. The court held that DOE's findings in this regard were supported by substantial evidence and the agency's analysis of competitiveness appropriately focused on the flexibility of the arrangement as a whole, not on its effect on domestic producers or on whether the gas could be supplied for less by others.

(4) On May 19, 1989, in New England Fuel Institute (NEFI) v. ERA, 875 F.2d 882 (D.C. Cir. 1989), the D.C. Circuit rejected claims of the association of competing fuel oil distributors that ERA had authorized a long-term import (up to 25,000 Mcf/day firm; up to 15,000 Mcf/day interruptible) of gas (Granite State Gas Transmission, Inc., 1 ERA Para. 70,717 (1989)) based on an inadequate showing of public interest (NEFI disputed the existence of "need" in the regional market Granite intended to supply), and that ERA had erred in denying its request for a trial-type hearing. The court found ERA had properly relied on the policy guideline presumptions and made findings based on substantial evidence, "including the presumptions." NEFI's complaints largely went to the merits of the policy

itself, the opinion concluded, and NEFI had not provided the government with sufficient evidence to place "material issues of fact genuinely in dispute."

(5) Independent Petroleum Association of America v. ERA (Case No. 88-1298). On October 12, 1989, the D.C. Circuit denied IPAA's petition for review of an ERA order granting Minnegasco, Inc. (1 ERA Para. 70,721), a local distribution company long-term authority to import up to 50,000 Mcf/d of gas on a firm basis and up to 110,000 Mcf/d on an interruptible basis directly from TransCanada Pipe Lines, Ltd., under a two-part rate. Domestic transportation was secured under separate contracts with more than one pipeline. The court rejected the same basic procedural and substantive challenges raised by producer groups in earlier cases. The opinion memorandum is not published.

(6) Most recently, on November 17, 1989, the D.C. Circuit dismissed for lack of standing a petition filed by Michigan Consolidated Gas Co. for review of an ERA order authorizing National Steel Corporation (1 ERA Para. 70,786) to import gas directly from Canada on a short-term blanket basis, in what the order characterized as a bypass of MichCon's system for use in National Steel's plant near Detroit. Michigan Consolidated Gas Co. (MichCon) v. ERA, No. 88-1791, slip. op. The proposal involved construction

of a pipeline under the Detroit River. MichCon argued that ERA misapplied the policy guidelines; that the import would only be competitive because National Steel saved the fixed costs it would otherwise pay MichCon, its principal local distributor, for service; and that there was no showing of need since gas was available from other, price-competitive sources. Additionally, MichCon argued that ERA's public-interest analysis should have considered the impact of the proposal on MichCon and its other ratepayers.

The D.C. Circuit had three months earlier upheld a FERC order authorizing Panhandle Eastern Pipe Line to bypass MichCon's facilities and to interconnect directly with National Steel. MichCon v. FERC, No. 88-1062. Following that decision, MichCon had disconnected its facilities serving National Steel. The court found it unnecessary to reach the merits of MichCon's arguments in the ERA proceeding because of this disconnection by MichCon, which left National Steel no choice but to buy gas on the open market. As a result, there was no cognizable, redressable injury, and, therefore, the court found MichCon had no standing to litigate its claim.

QUESTIONS FROM SENATOR BINGAMAN

Question 1: DOE's import policy guidelines state that: "if the imported gas is competitive in the proposed market area and, through its contract terms, will remain competitive throughout the contract period, then the rebuttable presumption exists that the gas is needed in that market." 49 Fed. Reg. at 6688. What kind of a showing must be made to rebut this presumption? Has this showing ever been made?

Answer: To rebut this presumption, opponents of an import proposal must demonstrate that the negotiated arrangement does not give the importer the flexibility to respond to changing market conditions, and that the importer has no markets for gas actually purchased under the arrangement. 49 *Fed. Reg.* at 6687. This showing has never been made.

QUESTIONS FROM SENATOR BINGAMAN

Question 2:	In your testimony, you indicate that DOE has found domestic producers' past claims regarding the impact of Canadian imports to be unsupported. Would your please expand on this? What were the claims and what documentation was submitted in support of such claims? What were the Department's findings?
Answer:	Over the past five years, domestic producers have intervened to protest, on substantially the same grounds, in a number of applications to import Canadian natural gas. These applications have requested both long-term and short-term, blanket import authority. In general, producers have argued that the Department could not rely on the 1984 import policy which producers claimed was invalid and, further, that the gas was not needed. "Documentation" generally has taken the form of "expert testimony" which repeated producers' arguments but did not offer information relevant to the Department's public interest inquiry. The Department has considered and rejected producers' challenges which have either ignored or reargued the Department's policy. Producers have failed to meet the burden of proof placed on them by section 3 of the Natural Gas Act and the policy guidelines to demonstrate that the import was not competitive and sufficiently flexible to respond to changing market conditions over the life of the agreement.

QUESTIONS FROM SENATOR BINGAMAN

Question 3: DOE's import policy guidelines state: "The contract arrangement must be sufficiently flexible to permit pricing and volume adjustments, as required by market conditions and available competing fuels, including domestic natural gas. Contract flexibility is a function of certain provisions which may include, but are not limited to: the volume of gas under contract, base price, price review or adjustment mechanisms, take-or-pay obligations, make-up provisions, length of the contract, and other terms which may affect the marketability of the gas." 49 Fed Reg. at 6688 (emphasis added). In past orders ruling on applications for authority to import natural gas under section 3 of the Natural Gas Act, has the Department addressed the effect that take-or-pay clauses have on the competitiveness of proposed natural gas imports? In terms of its effect on the competitiveness of natural gas imports, is a high demand charge as part of a two-part rate any different from a high take-or-pay requirement?

Answer: Take-or-pay and demand charge provisions are both based on the contract demand quantity and both impose fixed minimum payments on the purchaser regardless of volumes taken. In accordance with the policy guidelines, the Department considers take-or-pay clauses and demand charges together with all other provisions in a negotiated arrangement to determine whether an import is and will remain market-responsive over its term. The Department's analysis takes into account the relationship between any take-or-pay provision or demand change and the importer's ability to secure a supply commitment, and balances this reality against any diminution in flexibility.

QUESTIONS of SENATOR PETE V. DOMENICI (R-NM) for
MR. MARK SCHROEDER, DEPUTY GENERAL COUNSEL
U.S. DEPARTMENT OF ENERGY

Question 1. Please briefly describe all import authorizations applied for since the issuance of the 1984 Policy Guidelines, and indicate which were approved, rejected or withdrawn.

Answer: Since the Natural Gas Import Policy Guidelines were issued on February 17, 1984, the Department has received 416 applications, 372 of which have been import, or a combination of import/export, requests, and 44 of which have been export requests only. 281 of the import application requests have been authorized, 77 are pending a final agency decision, and 14 have been withdrawn. No import authorization requests have been rejected, although in one instance, Kern River Gas Supply Company, DOE Docket No. 86-12-NG, an application was withdrawn after the Department had proposed denial of the import request.

264 of the import applications received since the publication of the policy guidelines have been for short-term, blanket authorizations. DOE's blanket import program provides an authorization holder with blanket approval, within prescribed limits, to negotiate and transact individual, spot and short-term purchase arrangements without further regulatory action. Blanket authorizations are predicated on the presumption that spot or

short-term purchase transactions will only occur to the extent that there is a need for the gas and the arrangements are competitive.

In order to safeguard the public interest, blanket authorizations are limited to two-year terms, beginning on the date of first delivery. DOE requires import authorization holders to file quarterly reports detailing each sales transaction. In order to ensure that these authorizations continue to be in the public interest, DOE closely monitors sales made under these authorizations by examining and making public the data from the quarterly reports. Because of the two-year term limitation, blanket authorization holders must apply for a new blanket authorization periodically. For example, of the 33 blanket authorization requests received by the Department so far in 1990, 11 have been from current blanket authorization holders.

Also, applicants often request blanket authority to both import and export natural gas. 10

requests for blanket authority to import and export have been received by the DOE thus far in 1990.

108 of the import authorization requests received since 1984 have been other than blanket requests. Nearly a third of these applications have involved amendments to existing long-term authorizations where the Canadian supplier and the U.S. purchaser had renegotiated their purchase contracts specifically to meet the policy guideline criteria. Generally, this involved the replacement of contracts that had high, fixed prices at the border and high take-or-pay volumetric obligations, with new arrangements that incorporated market-responsive pricing terms, including two-part rate designs, automatic price adjustment and renegotiation provisions, and flexible volumetric terms.

Also, the unbundling of the natural gas market resulted in many pipeline suppliers becoming merely transporters of natural gas while their sales customers became direct purchasers. As a result, the DOE has received many requests for the

QUESTIONS FROM SENATOR DOMENICI

transfer of long-term import authority from pipelines to end users and local gas distribution companies. In addition, the Department has received numerous applications from direct purchasers/shippers, including primarily local distribution companies and sponsors of cogeneration projects, for new long-term authority to import natural gas.

QUESTIONS FROM SENATOR DOMENICI

Question 2: Some assert that the U.S.-Canada Free Trade Agreement binds the hands of FERC and DOE, preventing them from taking action under the Natural Gas Act to impose such terms and conditions on imports as may be necessary to mitigate anticompetitive or discriminatory aspects.

Senate Report No. 100-509 accompanying the Act which approved and implemented the Agreement makes it perfectly clear that that is not the case. For example, the Report states that:

> Sections 4 and 5 of the Natural Gas Act require rates and charges for interstate transportation of natural gas to be "just and reasonable" ... and not "unduly discriminatory, or preferential ...."
>
> * * *
>
> The FERC has authority under the Natural Gas Act to prescribe rules and regulations governing all transportation rates and charges.
>
> * * *
>
> . . . the Agreement does not in any way affect the ability of the U.S. regulatory authorities, including ERA and FERC, to impose appropriate terms and conditions on imports and exports of natural gas under the Natural Gas Act. The Committee sought, and received, assurances that nothing in the Agreement alters, supplants, or preempts the mandate of the Natural Gas Act or the Natural Gas Policy Act of 1978.

The Report also goes on at length to make it clear that the Agreement does not affect FERC Opinion No. 256. The Report quotes Canadian Ambassador Gotlieb that "The Canadian Government does not view FERC's as-billed decision as being inconsistent with or affected by the Free Trade Agreement." The report states that DOE Deputy Secretary Martin concurred in that assessment in testimony before the Committee on Energy and Natural Resources.

QUESTIONS FROM SENATOR DOMENICI

Moreover, in written testimony to the Committee FERC Chairman Martha Hesse summed up FERC's understanding of the effect of the Agreement. She stated:

> Inasmuch as the principal statutes under which the Commission operates already mandate nondiscriminatory treatment, the Free Trade Agreement does not in any way alter, supplant, or preempt that mandate. Similarly, since the Commission's policy, consistent with these statutory mandates, is one of nondiscriminatory treatment, we do not foresee any significant alteration or impact on the Commission's decisional processes in the future.

Upon review of the Free Trade Agreement, including the legislative history accompanying it, would you not agree that the Free Trade Agreement does not prevent DOE or FERC from reviewing the terms and conditions on imports of natural gas (including any arrangements, transactions or rates subject to the jurisdiction of the Department or the Commission) and from imposing such terms or conditions as may be necessary to offset or mitigate elements which are discriminatory, anticompetitive, preferential or not in the public interest?

Answer: As I responded to a similar question from Senator Nickles at the May 3rd hearing (page 44 of the hearing transcript), the Free Trade Agreement does not prevent or inhibit the DOE from reviewing proposed import arrangements to ensure that they are consistent with section 3 of the Natural Gas Act and the DOE 1984 Natural Gas Import Policy Guidelines, or from attaching such nondiscriminatory conditions as may be required by the public interest. Moreover, consistent with

QUESTIONS FROM SENATOR DOMENICI

your quote from the testimony of the former FERC Chairman, the Natural Gas Act and DOE policy already mandate nondiscriminatory treatment.

QUESTIONS FROM SENATOR DOMENICI

Question 3: FERC Opinion No. 256 applies only to sales gas, and not to transportation gas.

As a matter of policy, should the principles of Opinion No. 256 be applied to transportation gas? If not, wouldn't that create an enormous loophole for importing pipelines to escape the application of Opinion No. 256 simply by moving the point of sale outside of the U. S. and having only the transportation of such gas occur in the U.S.? If the principles of Opinion No. 256 are not applied to transportation gas, wouldn't that enable Canadian gas to gain an unfair advantage, which was the original problem which led the Commission to issuing Opinion No. 256?

Has DOE considered making the principles of Opinion No. 256 part of any import authorization for transportation gas?

Answer: Order 256 dealt with the as-billed passthrough of Canadian costs by a domestic pipeline to its downstream customers. The FERC issued Order 256 in order "to ensure that there is an equitable allocation of fixed costs between the domestic pipelines' high and low load factor customers" (*See* *Boundary Gas, Inc.*, 40 FERC Para. 61,047 (July 20, 1987) at 61,147). When the domestic pipeline is merely acting as a transporter for natural gas purchased directly, the as-billed passthrough issue does not arise and Order 256 is therefore not applicable.

In general, if a natural gas user elects to purchase gas and transportation separately, it pays the transportation rate approved by the duly authorized regulatory body. If the purchaser is transporting gas in Canada it pays the transportation rate approved by the NEB; if it is transporting gas within the U.S., it pays the transportation rate approved by the FERC. In the U.S., direct sales are not subject to FERC's ratemaking authority. Thus, Canadian gas and U.S. gas being transported between any two points in the U.S. are treated equally. Local distribution rates are subject to state public utility commission regulation.

Further, both Canada and the United States utilize two-part rates. The Department has found that the two-part rate design utilized in Canada and negotiated in import contracts is largely analogous to two-part rates found in domestic tariffs and that Canadian supplies do not enjoy a competitive advantage over domestic supplies as a result of rate design differences. [*See*, *e.g.*, *Natural Gas Pipeline of America*, 1 ERA Para. 70,645 (May 15, 1986)]. The FERC reached a similar conclusion in its May 2, 1990, decision on the *Niagra Import Points Projects*, CP88-171-000,

QUESTIONS FROM SENATOR DOMENICI

et al., at page 36, finding that its "responsibility is to insure that its regulatory policies do not frustrate the market from producing results most beneficial to consumers."

The existence of rate differentials between Canadian and domestic transportation rates, or, for that matter, the differences that exist among many domestic pipelines' rates, do not mean that a particular gas supply enjoys an uncompetitive advantage.

Nevertheless, DOE continues to be sensitive to allegations that the differences in rate design policy between Canadian and U.S. regulatory authorities creates governmentally imposed distortions in the market for natural gas. DOE will continue to closely monitor and analyze these issues and to assess their implications in the context of National Energy Strategy development.

QUESTIONS FROM SENATOR DOMENICI

Question 4:	You stated at the hearing that since 1984 the Department's policy with respect to the review of a proposed import is limited to a determination of whether the arrangement taken in its entirety is and will remain competitive over the life of the authorization. You also stated that the "Department believes the market, not the government, should determine the price and other contract terms for natural gas." The marketplace works if there is arms-length competition. However, in the case of Iroquois, the pipeline is one-third owned by the Canadian pipeline transporting the gas to the U.S. border, one-third owned by potentially competing U.S. pipelines, and one-third owned by the LDCs who will sell the gas. a. Does the Iroquois situation constitute a "competitive market place" in the traditional use of the term by economists?
Answer:	I still cannot comment on the specific facts of the Iroquois case, due to its pendency before DOE. However, I would like to make a comment on the general premise of this question. If there are competitive problems with local distribution companies having ownership interests in pipelines, or with producers having ownership interests in pipelines, or with vertical integration in the natural gas industry in general, they probably should be addressed generically. As to the first portion of this question, the DOE's preliminary findings were that the competitiveness of the arrangements were not

affected by the ownership of the participants in Iroquois. (See page 24 of Conditional Order 368). In general the Northeast does present a competitive marketplace for fuel. Not only do domestic and Canadian natural gas compete with each other but they must also compete with fuel oil, coal, electricity, and liquefied natural gas.

b. What specific standards and criteria are used by DOE in making its review under Section 3 of the Natural Gas Act? Are they the same as used by the Commission with respect to Section 7?

Answer: Section 3 of the NGA states that the DOE shall approve an import authorization request unless it finds it will not be consistent with the public interest. Issuance of a section 7 certificate requires a finding by FERC that proposed service is or will be in the public convenience and necessity.

With regard to import authorizations, the section 3 determination is guided by the DOE's Natural Gas Import Policy guidelines. Under the guidelines, the competitiveness of the import arrangements in the markets served is the primary consideration for meeting the public interest test, and, for long-term proposals, need for the gas supply and security of the supply are also important considerations. While the public interest standards of the two provisions are regarded as "substantially equivalent," the burden of proof under section 3 is the reverse of section 7 and "requires an affirmative showing of inconsistency with the public interest to deny an application ...." Panhandle Producers v. ERA, 822 F.2d 1105, 1111 (D.C. Cir. 1987).

c. What specifically does the Department review? The wellhead purchase contract? The contract for the transportation of the gas? The sale for resale contract?

Answer: The DOE policy guidelines state that the terms and conditions of an import arrangement, taken together, must provide a supply of gas that the importer can market competitively over the term of the contract. This generally involves review of the purchase contract between the U.S. importer and the exporter.

Since the majority of the import arrangements which the DOE has reviewed involve purchases from Canadian marketers or pipelines, and not purchases at the Canadian wellheads, the DOE does not review the wellhead contracts. In fact, many of these import arrangements involve price mechanisms pursuant to which the wellhead price is determined on a net-back basis, i.e., by deducting certain expenses, which can vary, from the eventual sales price, which can also vary over time. Only to the extent that the terms of wellhead purchase contracts are incorporated in the import contract and application would the DOE review them, and this occurs only infrequently.

Most of the import authorization requests received by the DOE, if they involve third-party transportation arrangements, will include copies of the transportation contract(s). The DOE does review these contracts, particularly with an eye to ensuring that the Department fully discharges its environmental responsibilities. In issues involving domestic pipeline transportation rates, DOE defers to FERC's jurisdiction.

Sales by the importer in the U.S. market generally come under the jurisdictional responsibilities of the FERC or the state PUC's.

d. Where does the Department make its determination about the competitiveness of the marketplace (e.g., where the sale takes place (even if in Canada); at the border; where the gas is to be consumed), and how does it make it?

QUESTIONS FROM SENATOR DOMENICI

Answer: The policy guidelines contemplate that the contract arrangements should be sufficiently flexible to permit pricing and volume adjustments as required by market conditions and availability of competing fuels, including domestic natural gas. In general, the DOE requires applicants requesting long-term import authorization to provide it with the gas purchase contract between the U.S. importer and the exporter, which is then considered by the DOE in making its competitiveness determination. However, the Department's principal concern is that the import arrangement will result in gas supplies that will be competitive in the ultimate market place, where the gas is consumed.

The Department makes its finding on competitiveness by examining proposed import arrangements to determine if the gas purchase contract's terms are sufficiently flexible to respond to changing market conditions. The DOE is assisted in this determination by the presumption that willing sellers and willing buyers, if free from unnecessary governmental interference, will negotiate market-responsive import arrangements.

QUESTIONS FROM SENATOR DOMENICI

e. How is the "public interest" considered? Does DOE review the downstream impacts, such as the price impact on consumers and the consequences to competing supplies of gas, and does it look at the markets into which the gas is to be delivered? Or is DOE's review limited to the narrow question of whether the terms of the contract are theoretically "market responsive" on their face?

Answer: The policy cornerstone of the public interest standard is competition. Competitive import arrangements are an essential element of the public interest, and natural gas imported under agreements that provide for the sale of gas in volumes and at prices responsive to market demands largely meet the public interest test. Unless demonstrated otherwise, ultimate consumers are presumed to benefit from increased supplies of natural gas under market-responsive contracts. The consequences of market-responsive import arrangements on competing supplies of gas will be to help ensure that those supplies are also sold on market-responsive terms. Finally, the DOE does consider the competitiveness of an import arrangement in the relevant market area. If the importer is a pipeline purchasing gas for its system supply, the arrangement should be competitive with other natural gas supplies available to the pipeline. If the importer is a

QUESTIONS FROM SENATOR DOMENICI

local distribution company, the arrangement should supply gas which is competitive with other natural gas supplies and competing fuels available in the LDC's market area.

QUESTIONS FROM SENATOR DOMENICI

Question 5:	When DOE issues an order authorizing the importation of gas, to what extent is the Commission precluded or preempted from exercising its statutory authority and responsibility under the Natural Gas Act and other relevant statutes to ensure that the transaction is not anticompetitive, not discriminatory and in the overall public interest?
Answer:	Once the DOE has approved an import arrangement, the FERC cannot act in a manner inconsistent with the actions taken by the Department. [See, e.g., Northwest Pipeline Corporation, DOE/ERA Opinion and Order No. 87, 1 ERA Para. 70,604 (September 10, 1985), at 17].

Nonetheless, Federal and State regulatory authorities retain substantial authority over pipelines and distribution companies. Opinion 256 is an example of an exercise of this authority. The FERC, under its Natural Gas Act authority to regulate the rates that domestic pipelines charge their domestic, interstate customers, required certain pipelines to reflect the costs of gas imported from Canada in a manner similar to the way pipelines reflect gas costs from domestic sources. FERC's action was not inconsistent with the DOE import authorization.

QUESTIONS FROM SENATOR DOMENICI

Question 6:	In issuing Order No. 368: a. Did DOE consider the potential anticompetitive effects of the provisions in the import contract which require shippers to pay all TransCanada demand charges regardless of how much gas is actually imported?
Answer:	Although DOE cannot discuss the specifics of Conditional Order No. 368, two-part demand/commodity rate structures are not unique to Canadian natural gas systems, and the DOE has found that the Canadian and U.S. two-part rate design methodologies are largely analogous. (See the response to Question 3 above).
	b. Did DOE consider the implications of the joint ownership position of TransCanada, U.S. pipelines and the LDCs, particularly those with respect to competition? Did DOE have any concern that the principal U.S. shippers are joint venturers with TransCanada, and that their interests are not entirely "arms-length"?
Answer:	The DOE did consider the implications of the ownership interests in Iroquois. The Department's preliminary finding on the issues that arise from the ownership interests can be found on page 24 of Conditional Order 368. Basically, the preliminary findings indicated that the competitiveness of the arrangements was not affected by the ownership of the participants in Iroquois.

QUESTIONS FROM SENATOR DOMENICI

c. Did the Department review the differences between U.S. and Canadian rate design, consider the impact of those differences on consumers, competition and domestic producers? Did the Department consider adding such terms or conditions to its Order as were necessary to mitigate those differences?

Answer: The DOE did consider rate design issues in making its preliminary findings in Conditional Order 368, as well as various requests for conditions. The DOE has not found the differences in U.S. and Canadian rate designs to be a significant factor in analyzing the competitiveness of the transaction.

QUESTIONS FROM SENATOR DOMENICI

Question 7: In the Department's opinion, does the ownership position of the LDCs in Iroquois provide any economic incentives for the LDCs to take Iroquois gas even if equally priced, or lower priced domestic gas is available? Did the DOE examine this issue before issuing Order No. 368?

Answer: The DOE is not in a position to give an opinion on how each of the 18 LDC's who comprise the applicants in the Brooklyn Union proceeding will manage their natural gas supply portfolios; however, the ownership interests in Iroquois were considered by the DOE prior to making its preliminary findings in Conditional Order 368. Please refer to my responses to Questions 4 and 6(b) above.

QUESTIONS FROM SENATOR DOMENICI

Question 8:	If the NEB imposed incremental tolling on TransCanada would that affect the "need" for the gas? Would it affect the economic viability of the Iroquois project?
Answer:	The Brooklyn Union import arrangements consist of a border price which is indexed to the cost of competing fuels regardless of how the proceeds from the natural gas sales would be divided among the various Canadian participants. Therefore, the Canadian tolling issue has no direct relevance to DOE's decision. Apart from this, I cannot speculate what effect such an NEB action would have on the participants in the Brooklyn Union proceeding. However, the precedent agreements to the Brooklyn Union purchase contracts do contain provisions pursuant to which regulatory approvals and licenses must be acceptable to all parties.

QUESTIONS FROM SENATOR DOMENICI

Question 9: Will DOE issue a final Order in the Iroquois proceeding before the Canadian regulatory process with respect to the tolling issue is completed?

Answer: The Department will issue a final Order in the Brooklyn Union proceeding after its NEPA review is completed and it has made final decisions on the environmental and other issues raised in the case. Because the Brooklyn Union import arrangements consist of a border price which is indexed to the cost of competing fuels regardless of how the proceeds from the natural gas sales would be divided among the various Canadian participants, the Canadian tolling issue has no direct relevance to DOE's decision.

QUESTIONS FROM SENATOR DOMENICI

Question 10: If Iroquois adds compression stations (which it does not now have), by how much could it increase its throughput? Did DOE consider this question before issuing its conditional order? Would Iroquois need to apply for an amendment to its DOE import authorization before importing the increased volumes that additional compression would allow?

Answer: The regulation of interstate pipeline facilities is a matter under the jurisdiction of the FERC. The DOE would examine any new construction in the context of its environmental review of a proposed action involving an amendment to an import authority or an application for import authority. In Conditional Order 368 the Department made preliminary findings only on the import arrangements before it. If Brooklyn Union, or any other shipper-applicant, wants to import additional volumes on Iroquois, they would have to amend their import applications to do so.

QUESTIONS FROM SENATOR DOMENICI

Question 11: Iroquois' sponsors assert that the contracts between Iroquois and its proposed shippers do not have to be reviewed in hearings because the contracts were entered into after arms-length negotiations and include a market-based price for gas. Could these contracts truly have been negotiated at "arms-length" given the relationship between the various parties to Iroquois, particularly the owners and the shippers? Did DOE review this question before issuing Opinion No. 368?

Answer: The DOE did consider the ownership interests in Iroquois in making its preliminary findings in Conditional Order 368, [see the answers to Questions 4 and 6(b)]. Examination of the transportation contracts between Iroquois and its customers is principally under FERC's jurisdictional authority.

Tenneco Gas

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May 29, 1990

Honorable J. Bennett Johnston
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D. C. 20510-6150

Re: Oversight Hearing on Northeast Natural Gas Markets

Dear Senator Johnston:

I enclose my answers to three additional questions you asked me in your May 14, 1990 letter relating to my testimony at the Committee on Energy and Natural Resources' May 3, 1990 hearing on natural gas markets in the Northeast.

I thank you again for the opportunity to appear before the Committee.

Sincerely,

Joseph E. Ramsey

Joseph E. Ramsey, Chairman
Iroquois Gas Transmission
System Management Committee

JER:tbb
Attachment

RESPONSES TO QUESTIONS FROM SENATOR JOHNSTON

1. Question: In your testimony you indicate that existing interstate natural gas pipelines serving the Northeast "stay essentially full on a year-round basis." Please document this statement by reference to individual pipelines and the utilization of their capacity for firm and interruptible service on a seasonal basis.

Response: Tennessee Gas Pipeline Company ("Tennessee"), Transcontinental Gas Pipe Line Corporation ("Transco") and Texas Eastern Transmission Corporation ("Texas Eastern"), with its subsidiary Algonquin Gas Transmission Company ("Algonquin") are the principal existing interstate natural gas pipelines serving the Northeast. I have attached a graph, with supporting data, showing that annual average capacity utilization of these pipelines ranges from a high of 100.8% for Algonquin -- indicating utilization at slightly higher than its certificated capacity -- to 92.2% for Texas Eastern. Annual average capacity utilization for all pipelines is just over 96%. This data does not show how much of the pipeline capacity is being used for firm and how much for interruptible service. In general, however, all available capacity to the Northeast is required to support firm sales and transportation services. Capacity is available for interruptible service only when firm service customers do not take their full service entitlements.

Pipeline capacity is shown on an annual average day. Because of high winter heating load, however, market demand in the Northeast must be evaluated on a seasonal basis. Thus, in summer months substantial pipeline capacity into the Northeast must be used for storage injections, while in winter months storage withdrawals allow actual deliveries in the Northeast to be well above pipeline capacity into the Northeast. As a result, capacity utilization in winter months is shown as well above 100%, while utilization in summer months is shown as well under 100%.

For comparative purposes, I have also attached a graph showing that capacity utilization in other market areas -- the Midwest U.S. and California -- is substantially lower than utilization in the Northeast U.S.

2. Question. In answer to a question from the Committee you indicated that today there exists underutilized pipeline capacity for the importation of Canadian natural gas into the United States. Please identify: (a) the particular pipeline capacity to which you refer; (b) the amount of capacity that is underutilized relative to the total amount of capacity that is available; (c) the periods during the year that this capacity is underutilized; and (d) how the utilization of this capacity compares to utilization factors on domestic U.S. pipelines and Canadian domestic pipelines.

Response: We have calculated monthly pipeline capacity utilization at all natural gas export/import points; this data is attached and is summarized in graphical form for major export/import points and those serving Northeast markets. Average capacity utilization for all export/import points was 70.7% in 1989, ranging from a high of 87.9% in December to a low of 61.5% in July.

Capacity utilization of Tennessee's Niagara import point -- which is the largest current import point into Northeast markets -- averaged 78.6%, ranging from a high of 85.7% in December 1989 to a low of 66.3% in September 1989. These figures are well below the 99.6% annual average utilization of Tennessee's overall system to the Northeast.

Smaller import points servicing the Northeast have even lower capacity utilization: 16.2% (Phillipsburg/Vermont Gas); 47.2% (Highwater/Shell); and 53.7% (Cornwall/St. Lawrence). However, these low utilizations reflect more the low load factor of underlying isolated markets rather than a lack of competitiveness of Canadian gas. For example, no U.S. pipelines serve Vermont; Phillipsburg exports serve as Vermont Gas' sole source of supply.

3. Question: In answer to a question from the Committee you stated that "Iroquois has been through a full evidentiary trial type hearing in the State of New York, and it was as extensive and covered every aspect of need, rate design, cost and environmental that a Federal evidentiary hearing would have provided." What legal effect did this hearing have with respect to the Federal Energy Regulatory Commission's obligation under the Natural Gas Act to make a finding whether the construction and operation of Iroquois is in the public convenience and necessity? Under what

authority did the New York state regulatory authorities hold this hearing? Precisely what issues were adjudicated in this hearing? What about issues affecting parties outside the State of New York?

Response: (a) The New York proceeding was conducted under Article VII of New York's Public Service Law. It was thus a statutory public proceeding which led to a formal determination by the New York Public Service Commission. The full record of the proceeding (which consists of more than 10,000 pages of hearing transcript, thousands of exhibits, tens of thousands of pages of discovery requests and responses and supporting documentation, two Recommended Decisions by the two presiding Administrative Law Judges, a final Commission decision [Opinion No. 89-42] and a Commission decision denying all rehearing requests) is a matter of official public record and the FERC is entitled to take official notice of the decisions and the record on which the decisions were based. The key portions of the record of the New York proceeding (most notably the two Recommended Decisions, the Commission's Opinion No. 89-42 and the Commission's order denying requests for rehearing) have been filed with the FERC and are now part of the evidentiary record at FERC. Iroquois has also filed all environmental data from the New York proceeding with the FERC in aid of FERC's environmental review under the National Environmental Policy Act.

(b) New York State regulatory authorities held this hearing under Article VII of the New York Public Service Law. Note that Iroquois voluntarily submitted to the Article VII process in order to obviate any debate over whether New York State had the right to require Iroquois to submit to the Article VII process. The U.S. Court of Appeals for the Second Circuit has subsequently ruled that New York cannot require a FERC-regulated pipeline to obtain an Article VII certificate. See National Fuel Gas Supply Corporation v. NYPSC, slip op., Docket No. 89-7458 (2d Cir. 1990). However, the National Fuel decision in no way invalidates an Article VII certificate voluntarily sought as a means of obtaining any state or local authorization which FERC itself might require as a condition of its federal authorization.

(c) The Article VII process resulted in a "Certificate of Environmental Compatibility and Public Need." Generically, the issues adjudicated were whether there is a public need for the proposed Iroquois pipeline and the natural gas to be delivered by it, and whether the proposed construction is compatible with all requirements of law governing the human and physical environment. Within these generic issues were scores of sub-issues relating to public need and environmental compatibility. Rather than list the issues, I am attaching hereto the table of contents of the two

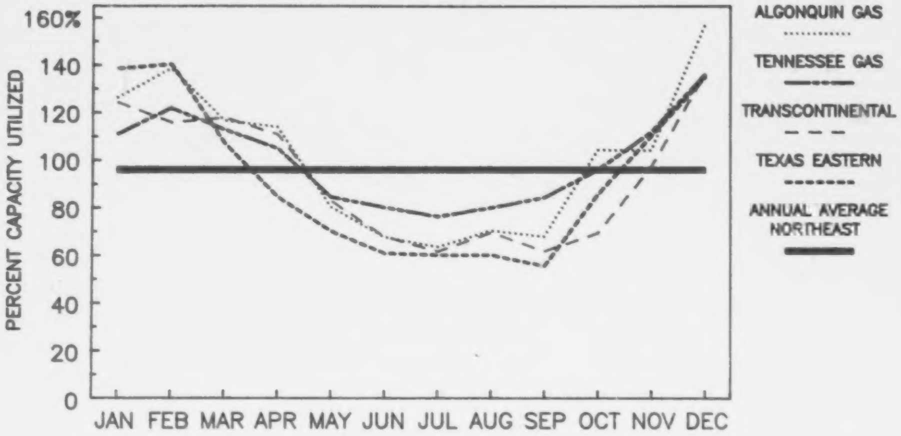
Recommended Decisions and the full text of Opinion No. 89-42. I would direct your attention to the list of appearances included in Opinion No. 89-42, which demonstrates the broad scope of interests represented on these issues in the Article VII proceeding.

(d) The scope of the New York Article VII hearings extended to issues beyond the boundaries of the state. For example, testimony was received on the need for natural gas in all states to be served directly or indirectly by Iroquois. Testimony was also received on alternatives to constructing the Iroquois pipeline (including reliance on existing pipeline systems); on the competitiveness of the gas supplies to be transported by Iroquois with alternative fuels (particularly oil); on the size and reliability of Canadian gas reserves; etc.

CAPACITY UTILIZATION BY U.S. PIPELINES

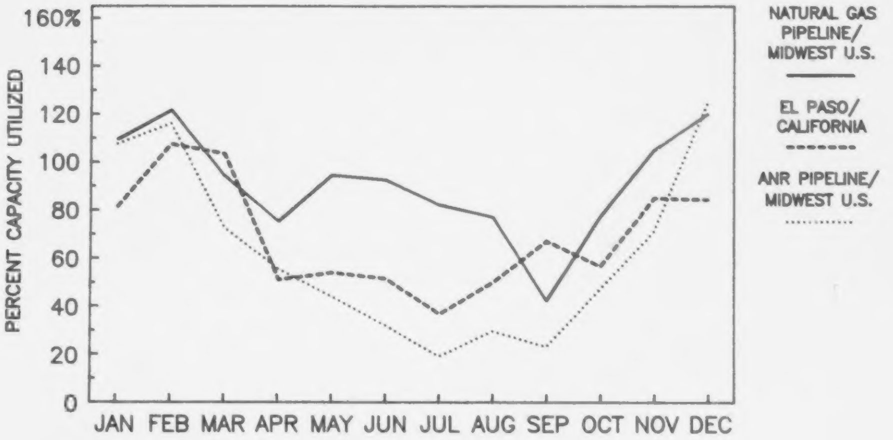
NORTHEAST U.S. MARKET AREA

1989



OTHER MARKET AREAS

1989



SOURCES: FERC FORM 16, SCHEDULE 1, LINE 17; FERC FORM 567; "1988 SURVEY OF U.S. NATURAL GAS STORAGE AND PIPELINE CAPACITIES," NATIONAL PETROLEUM COUNCIL, 1988.

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1989 U.S. INTERSTATE PIPELINES
CAPACITY UTILIZATION
VOLUMES IN MMCF

PIPELINE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
ALGONQUIN GAS TRANSMISSION	25138	24908	23197	21912	15959	13006	12620	13984	13038	20747	20038	31143	235690
CAPACITY	19859	17937	19859	19219	19859	19219	19859	19859	19219	19859	19219	19859	233827
UTILIZATION	126.6%	138.9%	116.8%	114.0%	80.4%	67.7%	63.5%	70.4%	67.8%	104.5%	104.3%	156.8%	100.8%
TENNESSEE GAS PIPELINE	104469	103717	105675	97831	80066	73177	71456	75035	76756	91569	103095	125947	1108793
CAPACITY	94106	84999	93588	93224	94737	91308	93720	93947	91114	95381	92106	95384	1113615
UTILIZATION	111.0%	122.0%	112.9%	104.9%	84.5%	80.1%	76.2%	79.9%	84.2%	96.0%	111.9%	132.0%	99.6%
TEXAS EASTERN TRANSMISSION	127038	116172	98115	74820	64263	53910	55025	54963	49140	78523	97800	123666	993336
CAPACITY	91495	82641	91495	88544	91495	88544	91495	91495	88544	91495	88544	91495	1077282
UTILIZATION	138.8%	140.6%	107.2%	84.5%	70.2%	60.9%	60.1%	60.1%	55.5%	85.8%	110.5%	135.1%	92.2%
TRANSCONTINENTAL GAS	120637	101535	114407	79211	61264	48480	45479	51340	44087	51180	91200	132158	940978
CAPACITY	96971	87587	96971	71487	73870	71487	73870	73870	71487	73870	93843	96971	982284
UTILIZATION	124.4%	115.9%	118.0%	110.8%	82.9%	67.8%	61.6%	69.5%	61.7%	69.3%	97.2%	136.3%	95.8%
PIPELINES TO NORTHEAST	377282	346332	341394	273774	221552	188573	184580	195322	183021	242019	312133	412814	3278796
CAPACITY	302432	273164	301914	272473	279962	270558	278945	279172	270363	280606	293711	303709	3407008
UTILIZATION	124.7%	126.8%	113.1%	100.5%	79.1%	69.7%	66.2%	70.0%	67.7%	86.2%	106.3%	135.9%	96.2%

5/24/90

1989 U.S. INTERSTATE PIPELINES
CAPACITY UTILIZATION
VOLUMES IN MMCF

PIPELINE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
ANR PIPELINE COMPANY	67370	65780	45546	31659	25930	18220	11190	17537	13220	27833	43206	78410	445901
CAPACITY	63860	57680	63860	58050	59985	58050	59985	59985	58050	59985	61800	63860	725150
UTILIZATION	105.5%	114.0%	71.3%	54.5%	43.2%	31.4%	18.7%	29.2%	22.8%	46.4%	69.9%	122.8%	61.5%
NATURAL GAS PIPELINE	109347	109714	94076	72760	94495	89443	82030	76968	40911	77465	101841	120365	1069415
CAPACITY	101835	91980	101835	98550	101835	98550	101835	101835	98550	101835	98550	101835	1199025
UTILIZATION	107.4%	119.3%	92.4%	73.8%	92.8%	90.8%	80.6%	75.6%	41.5%	76.1%	103.3%	118.2%	89.2%
EL PASO NATURAL GAS	71624	85432	90893	43485	47478	43759	32320	44099	57191	49904	72592	74482	713238
CAPACITY	89590	80920	89590	86700	89590	86700	89590	89590	86700	89590	86700	89590	1054850
UTILIZATION	79.9%	105.6%	101.5%	50.2%	53.0%	50.5%	36.1%	49.2%	66.0%	55.7%	83.7%	83.1%	67.6%

SOURCE: VOLUMES-FERC FORM 16, (TOTAL VOLUMES DELIVERED TO CUSTOMERS BY SYSTEM SUPPLY PLUS OTHER SOURCES, LINE 17, SCH 1)
CAPACITY- FERC FORM 567; NATIONAL PETROLEUM COUNCIL, "1988 SURVEY
OF U.S. NATURAL GAS STORAGE AND PIPELINE CAPACITIES." (CAPACITY IN MARKET AREA)

C.H. RONEY
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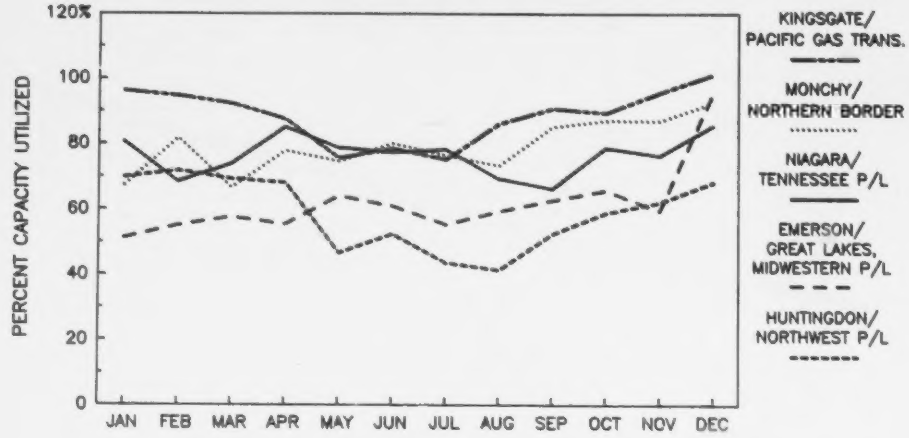
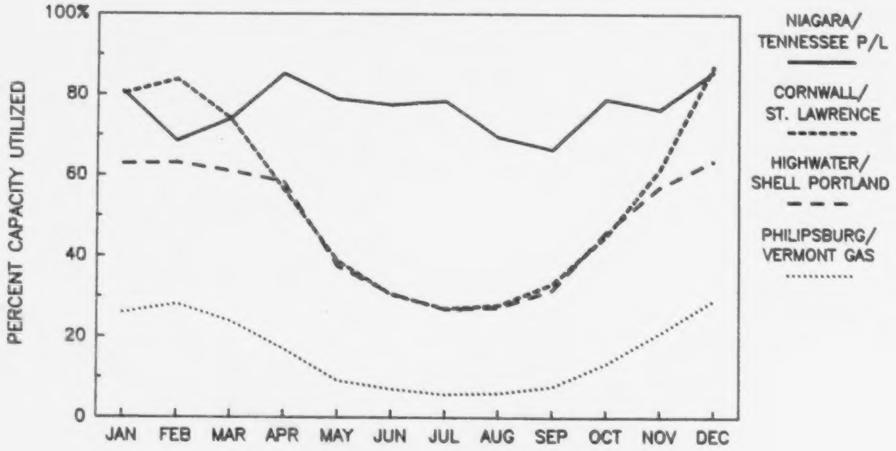
CAPACITY UTILIZATION AT CANADIAN IMPORT POINTS

MAJOR IMPORTATION POINTS
1989



NORTHEAST UNITED STATES
1989



SOURCES: "NATURAL GAS EXPORTS AND IMPORTS, MONTHLY STATISTICS", NATIONAL ENERGY BOARD; "THE CURRENT AND PROSPECTIVE ROLE OF CANADIAN NATURAL GAS IN THE UNITED STATES' MARKET", FOSTER ASSOCIATES, 1985 WITH UPDATES SUGGESTED BY PIRA

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5/17/90

1989 CANADIAN IMPORT POINTS
CAPACITY UTILIZATION
VOLUMES IN MMCF

EXPORT POINT/ IMPORTER	DAILY CAPACITY	-------DELIVERED VOLUMES/MONTH-------												
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
KINGSGATE/PGT	1550	46263	41156	44381	40803	36340	36547	36137	41398	42270	43076	44544	48728	501643
PER DAY		1492	1470	1432	1360	1172	1218	1166	1335	1409	1390	1485	1572	1374
UTILIZATION		96.3%	94.8%	92.4%	87.7%	75.6%	78.6%	75.2%	86.2%	90.9%	89.6%	95.8%	101.4%	88.7%
HUNTINGDON/NORTHWEST	800	17357	16122	17219	16375	11554	12611	10810	10279	12601	14621	14952	16951	171452
PER DAY		560	576	555	546	373	420	349	332	420	472	498	547	470
UTILIZATION		70.0%	72.0%	69.4%	68.2%	46.6%	52.5%	43.6%	41.4%	52.5%	59.0%	62.3%	68.4%	58.7%
CARDSTON/CDN MONTANA	58	0	33	0	0	0	0	0	0	0	0	0	370	403
PER DAY		0	1	0	0	0	0	0	0	0	0	0	12	1
UTILIZATION		0.0%	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	20.6%	1.9%
ADEN/CDN MONTANA	60	1131	913	822	652	670	577	538	533	781	1062	1052	992	9721
PER DAY		36	33	27	22	22	19	17	17	26	34	35	32	27
UTILIZATION		60.8%	54.3%	44.2%	36.2%	36.0%	32.1%	28.8%	28.7%	43.4%	57.1%	58.4%	53.3%	44.4%
MONCHY/NORTHERN BORDER	1100	23011	25216	22706	25743	25486	26477	26098	25024	28158	29780	28762	31629	318090
PER DAY		742	901	732	858	822	883	842	807	939	961	959	1020	871
UTILIZATION		67.5%	81.9%	66.6%	78.0%	74.7%	80.2%	76.5%	73.4%	85.3%	87.3%	87.2%	92.8%	79.2%
EMERSON/GLGT,MGT	1104	17599	17058	19786	18388	21985	20237	18962	20341	20799	22560	19694	32738	250147
PER DAY		568	609	638	613	709	675	612	656	693	728	656	1056	685
UTILIZATION		51.4%	55.2%	57.8%	55.5%	64.2%	61.1%	55.4%	59.4%	62.8%	65.9%	59.5%	95.7%	62.1%

5/17/90

1989 CANADIAN IMPORT POINTS
CAPACITY UTILIZATION
VOLUMES IN MMCF

EXPORT POINT/ IMPORTER		DAILY CAPACITY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
			-------DELIVERED VOLUMES/MONTH-------												
NIAGARA/TENNESSEE		207	5183	3973	4741	5288	5061	4814	5033	4456	4117	5061	5386	6244	59356
PER DAY	\1	235	167	142	153	176	163	160	162	144	137	163	180	201	163
UTILIZATION			80.8%	68.5%	73.9%	85.2%	78.9%	77.5%	78.4%	69.4%	66.3%	78.9%	76.4%	85.7%	78.6%
CORNWALL/ST LAWRENCE		43	1071	1009	986	728	517	395	361	372	428	601	795	1162	8425
PER DAY			35	36	32	24	17	13	12	12	14	19	27	37	23
UTILIZATION			80.3%	83.8%	74.0%	56.4%	38.8%	30.6%	27.1%	27.9%	33.2%	45.1%	61.6%	87.2%	53.7%
PHILIPSBURG/VERMONT		106	857	837	786	542	303	227	192	201	248	444	667	960	6264
PER DAY			28	30	25	18	10	8	6	6	8	14	22	31	17
UTILIZATION			26.1%	28.2%	23.9%	17.0%	9.2%	7.1%	5.8%	6.1%	7.8%	13.5%	21.0%	29.2%	16.2%
HIGHWATER/SHELL		40	779	707	757	701	464	370	334	339	379	569	686	790	6874
PER DAY			25	25	24	23	15	12	11	11	13	18	23	25	19
UTILIZATION			62.8%	63.1%	61.0%	58.4%	37.4%	30.8%	26.9%	27.3%	31.6%	45.9%	57.1%	63.7%	47.1%
MINOR POINTS		84	490	435	435	347	291	292	276	275	326	331	436	547	4481
PER DAY			16	16	14	12	9	10	9	9	11	11	15	18	12
UTILIZATION			18.8%	18.5%	16.7%	13.8%	11.2%	11.6%	10.6%	10.6%	12.9%	12.7%	17.3%	21.0%	14.6%
TOTAL EXPORTS TO U.S.		5180	113740	107460	112613	109567	102671	102544	98738	103218	110107	118105	116971	141112	1336852
PER DAY			3669	3838	3633	3652	3312	3418	3185	3330	3670	3810	3899	4552	3663
UTILIZATION			70.8%	74.1%	70.1%	70.5%	63.9%	66.0%	61.5%	64.3%	70.9%	73.5%	75.3%	87.9%	70.7%

\1 ADDITIONAL CAPACITY AVAILABLE BEGINNING 11/89 DUE TO NIAGARA SPUR EXPANSION.

SOURCE: 1989 VOLUMES-"NATURAL GAS EXPORTS AND IMPORTS, MONTHLY STATISTICS", NATIONAL ENERGY BOARD
CAPACITY- "THE CURRENT AND PROSPECTIVE ROLE OF CANADIAN NATURAL GAS IN THE UNITED STATES' MARKET", FOSTER ASSOCIATES, 1985
WITH UPDATES AND ADJUSTMENTS RECOMMENDED BY PIRA

C.H. RONEY
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APPENDIX II

Additional Material Submitted for the Record

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

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C. PAUL HILLIARD
CHAIRMAN OF THE BOARD

June 6, 1990

The Honorable J. Bennett Johnston
United States Senate
136 Senate Hart Office Building
Washington, DC 20510

Dear Mr. Chairman:

Thank you for holding open the record of the Senate Energy and Natural Resources Committee's May 3, 1990 Oversight Hearing on Northeast Natural Gas Matters for the purpose of receiving additional evidence. This letter and the attached additional report are designed to answer questions which arose during the course of that hearing and to bring to your attention other matters relevant to your consideration of this important subject. I ask that this letter and all attachments be accepted for the record.

As you are aware, the proceedings before the Federal Energy Regulatory Commission (FERC) and the Department of Energy (DOE) involving increased Canadian natural gas imports to the Northeast under discriminatory pipeline rate designs are of vital concern to domestic natural gas producers. Pending proposals threatening discrimination against domestic natural gas include Tennessee Gas Pipeline Company, Docket Nos. CP88-171-000, et al. (NIPS) and Iroquois Gas Transmission System, Docket Nos. CP89-634-000, et al. (Iroquois) among others.

Domestic natural gas producers applaud your efforts to achieve a level playing field for domestic and Canadian natural gas and are confident that you will take such steps as are necessary to assure this result. I am certain that American consumers in the Northeast will benefit from free and fair competition between domestic and Canadian suppliers of natural gas.

FERC's May 2, 1990 Order Issuing Certificates in NIPS approved the construction and operation of interstate pipeline facilities transporting imported Canadian natural gas at discriminatory rates. FERC rejected IPAA's assertions that this approval would result in undue discrimination against domestic natural gas. FERC's order attempts to differentiate this situation from those involving pipelines buying and reselling Canadian natural gas where FERC applies Opinion No. 256 to assure fair competition between imported and domestic supplies.

FERC is avoiding its responsibility to maintain a level playing field between domestic and Canadian natural gas. By stating that Opinion No. 256 applied to an interstate pipeline making a sale for resale subject to the Natural Gas Act and that FERC will do nothing to prevent identical discrimination against domestic producers with respect to so-called "transportation-only" pipelines, FERC opens a wide loophole through which the spirit of Opinion No. 256 can and will be eviscerated. Since the main problem addressed by Opinion No. 256 involved Canadian treatment of gathering and transmission costs imbedded in sales rates (not gas costs), FERC's distinction between sales for resale of Canadian gas (where FERC will apply Opinion No. 256) and "transportation-only" pipelines (where FERC will not) is specious.

Canadian natural gas imports enjoy a growing share of the U.S. market. Domestic producers can compete with imported gas on a level playing field. We are, however, justifiably concerned that approval of applications for transportation-only pipelines from Canada will displace sales by domestic producers simply because of the skewing of purchasing decisions directly attributable to the different rate designs employed by NEB and FERC. As Commissioner Trabandt noted in his May 3, 1990 concurring statement in NIPS, nothing in the U.S.- Canadian Free Trade Agreement, or any other treaty, statute, or court decision has relieved FERC of its responsibility under the Natural Gas Act to prevent undue discrimination in natural gas markets.

IPAA's position on Canadian gas imports for the Northeast is clear. IPAA wants an opportunity to show in a hearing on the record that approval of these and other similar applications by the FERC and DOE will result in:

1) Discrimination against domestic natural gas.

2) The elimination of cheaper transportation alternatives. (This issue must be examined now because the true cost of TransCanada's Iroquois-related expansion -- $2.6 billion -- was never revealed in FERC's "open-season" process. In other words, U.S. pipelines were prevented from showing Northeastern consumers better alternatives in that proceeding.)

Such a hearing could be convened and a record supplied to the Commission within 120 days without jeopardizing Northeastern consumers or the Canadian-supplied projects currently pending before FERC. Failure to convene such a hearing will result in harm to both domestic natural gas producers and consumers.

Our concerns outlined above can be succinctly stated as follows:

RATE DESIGN

- The rate designs for natural gas pipelines adopted by Canada's National Energy Board (NEB) and America's Federal Energy Regulatory Commission (FERC) are markedly different and create competitive distortions in natural gas markets. These competitive distortions affect the ability of U.S. pipelines and producers to compete effectively with Canadian pipelines and producers.

- The rate design required by FERC artificially places a significant portion of the total fixed costs of a domestic pipeline into the commodity cost component of the pipeline's rates. Conversely, the NEB pipeline rate methodology keeps these costs properly classified as fixed costs collected through a demand charge and assigns almost none of them to the commodity component.

- If a purchaser, like a local distribution company in the Northeast, buys gas from both Canada and the U.S., the decision as to which natural gas to buy on a daily or monthly basis is made based on the per unit cost of that incremental volume, i.e. the commodity charge, not the total unit cost of gas.

- The commodity charge for each unit of Canadian gas is equal to the wellhead price, plus other variable costs (mostly compressor fuel). The commodity charge for each unit of domestic gas is equal to wellhead price, plus other variable costs (mostly compressor fuel), plus substantial additional charges representing the pipeline's fixed costs which FERC assigns to the commodity component of a pipeline's rates. Thus, because of FERC's rate design policies, each additional unit of domestic gas is burdened with costs not present in the commodity charge for transportation of Canadian gas.

- Because of the differences in rate design, a purchaser faced with the choice of buying Canadian or domestic gas will compare commodity rates, rather than total prices. If so, the purchaser will always buy Canadian gas unless the domestic producer reduces its wellhead price by an amount at least equal to the amount of fixed costs FERC assigns to the pipeline's commodity component. (As reflected in the attached report, the disadvantage suffered by domestic producers will vary from at least 18 to 42 cents per Mcf depending on what assumptions are used. **10 cents per Mcf means 1.8 billion dollars per year to domestic natural gas producers**.) The attached report shows how the disparate rate design will result in cost shifting to non-Iroquois purchasers on domestic pipelines serving the Northeast and will send domestic pipelines serving the Northeast into a spiral of escalating transportation costs, making it even harder for domestic producers to compete.

- The disadvantage suffered by domestic producers and pipelines carrying domestic gas is present whether the Canadian-supplied pipeline is operating as a merchant or merely as a transporter of natural gas. This is true because, as stated above, the anticompetitive effect of Canadian rate methodology in American markets results from the different way Canada and the U.S. treat fixed gathering and transmission costs, and has nothing to do with "gas costs."
- This problem is apparent in a project like Iroquois, where Northeast LDCs purchase gas supplies in Canada and transport the gas from Alberta to the New York border on TransCanada's system. Under TransCanada's fixed-variable rate design, these gas supplies have a direct competitive advantage because FERC will not permit U.S. pipelines to implement a rate design competitive to that used by TransCanada for 2,000 miles of transportation. Thus, even if a competing U.S. pipeline were built, supplies carried by the U.S. pipeline would always be second choice because FERC's assignment of fixed costs to the commodity component makes domestic gas appear more expensive.
- This rate design difference is the primary reason that only minuscule amounts of U.S. gas are sold in Canada despite the fact that most of our production is much closer to eastern Canadian markets than their own production in Alberta.

REACTION FROM DOE/FERC

- Neither DOE nor FERC appear willing to remedy this discriminatory situation or allow a limited evidentiary hearing to examine two crucial issues: (1) the discriminatory impact of FERC-imposed pipeline rates when domestic gas competes for the same markets with Canadian supplies and (2) the availability of cheaper, domestically supplied alternatives based on the same rate design used in Canada.

- In January, DOE ignored our allegations regarding undue discrimination by Iroquois and authorized the Iroquois imports under a tilted, two-part demand/commodity border price. Instead of evaluating our evidence on the merits, DOE chose to defer to FERC saying IPAA's problem is with pipeline rates.

- FERC's May 2 order approving the Niagara Import Point Settlement (NIPS) dismissed our evidence of undue discrimination without reaching the merits saying that FERC is bound by DOE's import authorization, the Free Trade Agreement prohibits action to cure these inequities, and the place for IPAA to raise these issues is in each pipeline's rate case. Since this case-by-case initiative would cost us the equivalent of IPAA's annual budget, it is tantamount to rejection on the merits. Even if IPAA were able to prosecute successfully such an effort, it would take years and costly import-related facilities (which might not otherwise have been built if this discrimination had been remedied up front) will be in service, hurting consumers and producers alike.

- Although DOE and FERC in part base their lack of action to remedy discrimination against domestic natural gas on the U.S.-Canada Free Trade Agreement, such reliance is completely misplaced. As the legislative history developed by your Committee and Commissioner Trabandt's concurrence show, both DOE and FERC have obligations under the Natural Gas Act to evaluate any alleged anticompetitive or discriminatory impacts caused by their actions and to remedy undue discrimination where it is found. The Free Trade Agreement in no way prevents the DOE or FERC from investigating and curing such anticompetitive effects.

IMPACT ON CONSUMERS

- Approval by FERC of Iroquois, or any other $600 million project, without an evidentiary hearing is unheard of and in fact has never happened before in a regular certificate proceeding. Such precipitous approval also has serious implications for U.S. consumers who will have to bear all of these costs:
  - After these expensive facilities are constructed, Northeast markets will be locked into purchasing Canadian supplies regardless of the existence of more reasonably priced domestic gas supplies available at the wellhead.

- Capacity additions to the Northeast by U.S. pipelines will be discouraged as Canadian gas backs out domestic supplies. Domestic gas will also become even more expensive to transport as load factors decline.

- End users and local distribution companies which own equity interests in Iroquois are likely to utilize those facilities in preference to others simply because of their investment in the project. This too could harm consumers.

- The discriminatory impact upon domestic producers will eventually harm consumers directly. Drilling activity has been at historic lows for more than four years and the wellhead price of gas is equal to oil at about $10 per barrel, well below the replacement cost of gas. Sharply lower wellhead prices, which will result from discrimination against domestic gas, mean even less drilling, a declining resource base, and potential sharp increases in the price of gas when supply and demand finally come back into balance.

- The sponsors of Iroquois and Senator Bradley would have people in the Northeast believe that, unless Iroquois is constructed without a hearing and without delay, Northeast consumers will freeze or be forced to increase reliance on fuel oil during the winter of 1991-1992. Nothing could be further from the truth. In fact, the NEB has not determined whether TransCanada's related $2.6 billion (Canadian) expansion is even economic. The NEB is not expected to act until at least September 1990). It is therefore questionable whether Iroquois can be in service for 1991-1992 regardless of FERC action.

CHEAPER AND ENVIRONMENTALLY BETTER DOMESTIC ALTERNATIVES

- There is no question that domestic pipelines could add incremental facilities, such as additional compression and parallel pipelines along existing rights-of-way to meet peak day growth in the Northeast by November 1991, when Iroquois hopes to begin operation. U.S. pipelines could begin construction in time for completion by November 1991. There are several existing and planned U.S. pipeline proposals that can meet 1991-1992 winter heating demands in the Northeast **much cheaper** than Iroquois.

- ANR (American Natural Resources) FERC Docket No. CP89-637, Texas Gas Transmission-FERC Docket No. CP89-688, CNG-FERC Docket No. CP89-638 and Transcontinental Gas Pipeline-FERC Docket No. CP90-687 are pending proposals which could be phased to provide more than enough gas service to the Northeast by the 1991-1992 winter season.

- The project combining transportation service by Texas Gas and Transco could offer service to Northeast markets at rates less than one dollar per Mcf -- less than half the cost of transportation of Canadian gas over TransCanada and Iroquois. Furthermore, other domestic and Canadian supplied projects could get quick treatment under FERC Optional Expedited Certificate process and bring more than enough capacity to meet Northeast needs within the 1991-1992 time-frame using combined facilities of Northern Border Pipeline, ANR, Texas Gas, Panhandle Eastern, Texas Eastern and Columbia Gas Transmission Corporation.

- Any of these combined projects could be authorized by July 1991 and provide service by November 1991. In other words, there is plenty of time for FERC to review and approve these proposals. There is no natural gas supply emergency in the Northeast. Thus, there is plenty of time to hold a hearing on anticompetitive rate designs and to examine alternatives to Iroquois without putting consumers in jeopardy. In fact, for FERC to do anything else will harm domestic producers and force Northeastern consumers to bear huge, avoidable costs related to the Iroquois project.

IPAA is sensitive to the difficulties encountered by the FERC and DOE in addressing these complex and important issues. We also understand how tough these issues are for members of the Senate Energy and Natural Resources Committee and its staff. With this in mind, IPAA offers the attached report prepared by Prather Energy Consultants, Inc. (PEC) as a response to questions which arose in connection with the May 3 hearing.

Since the Committee's May 3, 1990 oversight hearing on Canadian natural gas imports, allegations of improprieties at the FERC have surfaced that deserve this Committee's attention. On May 18, 1990, Dr. Anne Marie Mueser and the GASP Coalition, opponents of the Iroquois project, filed a motion for investigation to determine the scope of ex parte contacts and to impose sanctions in those proceedings. On Friday, June 1, 1990, Dr. Mueser filed a formal request for oversight on this matter by the Senate Energy and Natural Resources Committee. Dr. Mueser has alleged that top decision-making members of FERC staff held secret, substantive meetings with the proponents of the Iroquois and NIPS projects on March 15 and 16, 1990. She further alleges that certain promises of favorable action on these contested applications by the end of June 1990 were made at these meetings.

If true, these allegations would indicate that FERC's processes have been tainted and that the public interest has been compromised. Needless to say, a FERC staff promise of favorable action on Iroquois' application by the end of June certainly amounts to a discussion of the merits. FERC officials involved in such *ex parte* contacts are subject to a code of conduct similar to that which applies to federal judges and must disqualify themselves from any proceeding in which impartiality might reasonably be questioned. This requirement is based, as now Supreme Court Justice Kennedy has observed, on the "general rule that the appearance of partiality is as dangerous as the fact of it." *United States v. Conforte*, 624 F.2d 869, 881 (9th Cir. 1980), *cert. denied*, 449 U.S. 1012. The documentation provided by Dr. Mueser raises a reasonable question as to the partiality of certain FERC officials and a full investigation is warranted.

At one point in his opening statement on May 3, Senator Bradley expressed grave concern that the Committee's oversight hearing on Canadian natural gas imports could be perceived as an attempt "to unduly influence the way FERC and DOE are handling the on-going Iroquois application." Whether or not one shared Senator Bradley's concern at that time, and I did not, the most recent developments regarding substantiated allegations of secret meetings attended by the Iroquois applicants and FERC officials in contested proceedings clearly involve the precise type of activities for which Senate oversight authority is intended. If proven, these allegations would also reveal which parties in this proceeding have actually been attempting to "unduly influence" the FERC.

The Natural Gas Act, the Administrative Procedure Act, and the Government in the Sunshine Act are all designed to assure that the rights of parties in contested cases are respected and that decisions by regulatory agencies are based on record evidence available for scrutiny by all interested parties and the courts. If Congress had intended for regulated entities to be able to meet behind closed doors with their regulators in contested cases, these statutes would be different. The reason *Congress mandated on the record decision-making* at FERC is that it recognized that regulation of multi-billion dollar utilities brings with it the possibility that the utilities will seek special treatment from the regulators. Congress decided that such a practice would be inimical to the public interest. In your capacity as Chairman of the oversight committee with responsibility for protecting the integrity of FERC's procedures, I urge you to use your authority to conduct an independent investigation to assure that there has been no violation of the public trust at FERC and to take appropriate actions in the event that such violations are uncovered.

CONCLUSION

You know, a lot of folks think we are fighting a losing battle to achieve fairness in North American natural gas markets. Even some people who agree with us suggest that there is no way FERC will ever give us a hearing on Iroquois because the project is a house of cards which would collapse under the scrutiny that a hearing would bring to bear. This would, they say, be politically unacceptable. I do not share this cynical view of American government. I believe that FERC will eventually see its duty to hold a hearing and take evidence on the issues raised in this letter and elsewhere.

In any case, IPAA "cannot remain silent in the face of Iroquois' request for regulatory approval of rate and pricing arrangements that would ensure that Iroquois' capacity would be utilized even if there were no need for added capacity in the markets proposed to be served." Instead, we "must vigorously object to those aspects of Iroquois' gas pricing and transportation rate proposals that would distort the market by permitting Iroquois shippers to buy gas from Canadian supplies under rate structures which Tennessee and other [domestic] suppliers are prohibited by the Commission from offering." We believe that "a full and complete hearing must be held to resolve the many genuine and material issues of fact that have been raised by Tennessee, other intervenors, and Iroquois itself. Moreover, those issues should be decided on an evidentiary record without any presumption that Iroquois' application or any of its proposals are in the public interest." These quotes are from Tennessee Gas Pipeline Company's Motion to Intervene, Protest, and Request for Hearing filed in Iroquois' original certificate application Docket No. CP86-523-002 on June 22, 1987. This pleading was filed before Tennessee became a part of the problem by taking a 12.8 percent equity position in Iroquois and making deals which will allow it to construct millions of dollars worth of new Tennessee facilities in connection with the Iroquois project. As you recall, Mr. Ramsey, Vice President of Business Development, Tenneco Gas, testified on behalf of Iroquois on a panel with me before your Committee. We are also including for the record a study by Charles J. Cicchetti on behalf of Tennessee Gas Pipeline Company filed by Tennessee on March 9, 1987 in that docket.

Other things being equal and with domestic supplies 1,000 miles closer to the Northeast than are Canadian supplies, domestic gas should be cheaper and available upon reasonable terms. Other things being equal, domestic producers would be willing to sign contracts similar to those entered into by

Canadian producers. But, things are not equal and until they are, domestic producers, pipelines, and consumers will not enjoy the benefits of a competitive North American natural gas market that is both free and fair.

Sincerely,

Paul Hilliard

C. Paul Hilliard

enclosures

INDEPENDENT PETROLEUM ASSOCIATION of AMERICA

Report On The
Iroquois Project-Impact on Domestic Producers

June 1990
PRATHER ENERGY CONSULTANTS, INC.
Alexandria, Virginia

Report On The
Iroquois Project-Impact on Domestic Producers

Prepared For The

INDEPENDENT PETROLEUM ASSOCIATION of AMERICA

Executive Summary

This Report quantifies the practical impact of the rate design disparity between the National Energy Board (NEB) and the Federal Energy Regulatory Commission (FERC or Commission). The general conceptual concerns were expressed in early 1989[1] and more fully described by this Report. The study attached to this Report validates the conclusions reached in the May 1989 Report.

In order to project illustrative transportation costs to deliver gas from various producing basins to the Northeast, the study makes a range of assumptions regarding the degree of domestic and Canadian pipeline utilization and the extent of new load additions.[2] Comparisons of the resulting demand and commodity rates give a measure of the "rate tilt" which favors Canadian gas under a wide variety of the possible factual scenarios. This competitive disadvantage against domestic production (and the resulting higher costs to gas consumers) stems from the current disparity in U.S. and Canadian rate designs. The study evaluated nine specific cases, each under the same growth/load factor scenarios. The cases are as follows:

> (Case 1) TransCanada's facility costs associated with the expansion of its system to serve the Northeast are, for rate design purposes, rolled-in with the costs of existing facilities.

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[1] Report on U.S. and Canadian Pipeline Ratemaking on Behalf of the Independent Petroleum Association of America, May 1989. Attached as Exhibit B to Mr. Hilliard's Starment before the United States Committee on Energy and Natural Resources, May 3, 1990.

[2] Growth Assumption I represents a 25 percent increase in the existing natural gas demand of the market.
Growth Assumption II represents a 100 percent increase in the existing natural gas demand of the market.

(Case 2) TransCanada's facility costs associated with the expansion of its system to serve the Northeast, for rate design purposes, are treated on a stand alone or "incremental" basis.

(Case 3) Domestic pipeline facility costs associated with expansion to serve the Northeast, for rate design purposes, are rolled-in with the costs of existing facilities. Three traditional producing basins were considered.

(Case 4) Domestic pipeline facility costs associated with expansion to serve the Northeast, for rate design purposes, are treated on a stand alone or "incremental" basis.

(Case 5) Domestic pipelines' existing facilities are used to deliver natural gas into the Northeast from the Gulf Coast. Three pipelines system were considered.

In order to make a valid comparison of these five cases in a timely manner, a unit cost approach was employed using publicly available data. The same daily and annual quantities were used for each case.

The ratios of the variable and commodity costs to the total costs were developed individually from available information. These ratios represent the percentage of specific transportation costs (variable and commodity) included in a particular pipeline's total average cost. By using these ratios it is possible to determine the unit fixed, variable, demand and commodity costs related to the pipeline system being studied knowing its total unit cost. This then permits a valid comparison using the data set forth on Exhibit D, without undertaking a extensive cost-of-service study.

The results of these case studies are set forth in the Table[3] shown below. The Table also compares the Canadian Scenarios (Cases 1 and 2) with the same Scenarios for domestic pipeline systems. Lines 1 through 9 show the illustrative transportation costs.

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[3] The numbers in parenthesis indicate that the Canadian's average or commodity costs are less than the domestic supplied scenarios. A complete discription of this table is contained in the body of the report.

Lines 10 through 13 show the difference between these costs and the TransCanada transportation rate, assuming it is rolled-in with rates charged to TransCanada's current customers. Line 14 through 17 show the differences with TransCanada's rates on a incremental design. The increasing benefits that the Canadians enjoy in Scenario II (column g) over Scenario I (column e) and over the Base Scenario is attributable to the loss of annual load by the domestic pipeline systems as the Canadians acquire a greater percentage of the market. The short-term result is that domestic producers would have a 18-42 ¢ disadvantage in acquiring part of the growth market of the Northeast. In the long-term under the greater growth in market represented by Scenario II, this disadvantage becomes even greater (38-68 ¢).

Table

		Base Scenario Proportional Market Sharing Growth Assumption I			Commodity Price Based Market Sharing				
					Scenario I Growth Assumption I		Scenario II Growth Assumption II		
Line No.	Cases	Average	Variable	Commodity	Average	Commodity	Average	Commodity	Line No.
		a	b	c	d	e	f	g	
1	1-Canadian: Rolled-In	$1.69	$0.20	$0.36	$1.23	$0.27	$1.27	$0.27	1
2	2-Canadian: Incremental	$2.00	$0.25	$0.44	$1.57	$0.33	$1.57	$0.33	2
3	3a-Midcontinent	$1.29	$0.30	$0.61	$1.41	$0.67	$1.94	$0.92	3
4	3b-Arkoma	$1.17	$0.29	$0.63	$1.29	$0.69	$1.76	$0.94	4
5	3c-Gulf Coast	$1.15	$0.29	$0.57	$1.26	$0.62	$1.73	$0.85	5
6	4-Domestic: Incremental	$1.13	$0.17	$0.47	$1.23	$0.51	$1.69	$0.71	6
7	5a-Tennessee	$0.64	$0.10	$0.37	$0.70	$0.40	$0.97	$0.55	7
8	5b-Transco	$0.81	$0.12	$0.28	$0.88	$0.31	$1.21	$0.42	8
9	5c-Tetco	$0.74	$0.20	$0.33	$0.81	$0.36	$1.12	$0.50	9
	Canadian Charges Over (Under) Domestic With Rolled-in Canadian Transportation Rates								
10	3a-Midcontinent	$0.40	($0.10)	($0.26)	($0.18)	($0.40)	($0.67)	($0.66)	10
11	3b-Arkoma	$0.52	($0.08)	($0.27)	($0.05)	($0.42)	($0.49)	($0.68)	11
12	3c-Gulf Coast	$0.54	($0.09)	($0.21)	($0.03)	($0.35)	($0.46)	($0.58)	12
13	4-Domestic: Incremental	$0.56	$0.03	($0.12)	($0.01)	($0.25)	($0.43)	($0.44)	13
	Canadian Charges Over (Under) Domestic With Incremential Canadian Transportation Rates								
14	3a-Midcontinent	$0.80	($0.05)	($0.18)	$0.16	($0.34)	($0.37)	($0.59)	14
15	3b-Arkoma	$0.92	($0.03)	($0.19)	$0.29	($0.36)	($0.19)	($0.61)	15
16	3c-Gulf Coast	$0.94	($0.04)	($0.13)	$0.31	($0.29)	($0.16)	($0.52)	16
17	4-Domestic: Incremental	$0.96	$0.08	($0.03)	$0.34	($0.18)	($0.13)	($0.38)	17

The conclusions readily apparent from these cases are that because of the difference in ratemaking methodologies the Canadians will acquire a disproportionate share of the growth market. If the current regulatory distortions permit Canadian gas to gain a disproportionate share of the growth in the Northeast gas market, they will be able to leverage the resulting higher load factors on their Canadian pipelines to displace the domestic sales to the existing Northeast gas market.

Report On The Iroquois Project-Impact on Domestic Producers

Prepared For The

INDEPENDENT PETROLEUM ASSOCIATION of AMERICA

Introduction

This Report was undertaken to develop answers to certain generic questions and to provide a measure of the impact on domestic producers if Iroquois-type projects are approved to serve the market growth of the Northeast. The attached studies amplify the exhibits[1] to Mr. Hilliard's May 3, 1990 Statement before the United States Senate Committee on Energy and Natural Resources, which demonstrated the effect of pipeline rate design on competition between domestic and Canadian producers. The specifics of the basic data and the assumptions used in these studies are discussed under individual sections of this report.

The basic questions are: (1) The effect of the difference between straight fixed variable (SFV) (which is used in Canada) and modified fixed variable (MFV) (which is used in the United States) rate design have in the real world of Northeast gas markets, and (2) The effect of other variables (such as the distance that gas must travel to reach the Northeast, the underlying cost of the competing pipeline systems and the extent to which they have been depreciated, the cost of expanding pipeline capacity and the methodology for allocating this cost among classes of rate-payers) on the rates for transporting domestic and Canadian gas to the Northeast.

The effect of the differences in rate design are demonstrated in the case studies attached. The other variables are discussed in the first section of this report.

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[1] The "Exhibits" referenced throughout this Report are those attached to Mr. Hilliard's May 3, 1990 Statement, unless otherwise referenced.

These studies confirm that the difference in ratemaking methodologies supports Mr. Hilliard's May 3 testimony that "The Canadian producers have a distinct economic advantage over their counterpart in the United States in stiff competition for the same markets."[2] These new cases serve to provide specific results to the more general principles described in Exhibit B.

Effect of Other Variables

The three most significant factors that effect the overall costs to provide natural gas service to a particular location, like the Northeast, are: (1) distance, (2) the vintage of the facilities, and (3) load factor. In order to compare the effects of these factors on access to Northeast markets, eight alternative transportation routes to supply the Northeast were considered. These are depicted in Mr. Hilliard's Exhibit D. The data contained in Exhibit D and the current mileage rates for transportation on Transcontinental Gas Pipe Line Corporation (Transco) at or upstream of Compressor Station 65 were used to develop the following tabulation.

Regarding distance, the map contained in Exhibit D shows the inherent advantage which, under an appropriate rate structure, would permit domestic supplies from the Midcontinent, Arkoma and Gulf Coast supply basins to compete effectively against imported supplies because of the lower average cost of transportation compared to gas being transported from Alberta.

Transportation Route	Average Cost per 100-Dth mile	Distance (in miles)
Alberta-New York-Rolled-In	7.3 ¢	2,300
Alberta-New York-Incremental	9.1 ¢	2,300
Alberta-Lebanon, OH	6.6 ¢	1,600
Midcontinent-New York	7.2 ¢	1,800
Arkoma-New York	7.2 ¢	1,300
Gulf Coast-New York	8.2 ¢	1,400
Lebanon, OH-New York	8.7 ¢	600
Transco	7.4 ¢	n/a

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[2] Introduction to Exhibit B.

In the mid 1960s when major long-line pipelines from the Gulf of Mexico to the Northeast were being constructed, the cost for transportation of natural gas from the Gulf Coast to New York at 100 percent load factor ranged from 1.4 to 1.6 ¢ per 100 miles. Since that time, significant increases in construction costs have occurred. For example, inflating the average 1.5 ¢ per 100 miles at 5 percent per year yields a cost today of 8.3 ¢ per 100 miles which corresponds with the costs shown above. Also, the above tabulation demonstrates a great similarity between Canada and the U.S. in the unit cost of facilities per 100 miles with new incremental facilities in the range of 9.0 ¢ per 100 miles and the rolled-in projects in the mid - 7 ¢ range.

Actual load factors will affect the marketability of gas. However, because Northeast customers are required to execute long-term contracts prior to the construction of any of the competing projects, purchasing decisions are being based on assumptions about projected load factors. The effect of load factor can be shown by using the Alberta to New York rolled-in average cost of 7.3 ¢ per 100 miles. Assume that this number was developed at a 90 percent load factor and that the variable costs for performing the transportation are 1.1 ¢ (15 percent of the total). The unit costs change when the load factor changes as follows:

Load Factor	Average Unit Costs in ¢ per 100 miles		
%	Total	Fixed	Variable
90	7.3	6.2	1.1
100	6.7	5.6	1.1
50	12.3	11.2	1.1

Basic Data and Assumptions

In order to conduct the necessary studies, certain assumptions are necessary in order to present results on a consistent basis. Three different volume assumptions for the incremental Northeast market are as follows:

Total Daily Market Demand

Present	400,000 Dth per day
Growth Assumption I	500,000 Dth per day
Growth Assumption II	800,000 Dth per day

Total Annual Market demand - 75% Load Factor

Present	109,500,000 Dth
Growth Assumption I	136,875,000 Dth
Growth Assumption II	219,000,000 Dth

The choice of the specific daily demand quantities listed above was one of convenience rather that precision. The important consideration was that of the relationship among the quantities being supplied from Canadian and domestic sources. A quick review of the approved and pending import projects indicates that if all of these projects are constructed, they will amount to approximately 20 percent[3] of the total Northeast peak day demand. The use of a 75 percent load factor to develop the annual quantities is based on experience and the knowledge that any composite market area, such as the Northeast, has a higher peak day requirement that an average day requirement. Some particular pipelines that have a high concentration of consumers with alternate fuel capability; peaking facilities, e.g., underground storage; or the lowest commodity rates in the major market area will be able to operate at a high load factor, possibly approaching 100 percent. But, the market area itself will not normally be able to sustain a composite load factor in the excess of the assumed 75 percent. This is true regardless of the nature of the customer mix, because even industrial and cogeneration loads are likely to take gas at less than their full contractual entitlement on an annual basis.

Case Description and Assumptions

Nine separate cases develop the results regarding the advantage which Canadian gas will enjoy in the Northeast. Two cases are based on the cost to import Canadian gas and seven are based on domestic supplies. In the seven domestic cases the daily quantity is held constant with the annual quantity varying according to the assumptions. Each case has three scenarios reflecting the assumptions as follows:

Base Scenario - Proportional Market Sharing
Growth Assumption I

The Canadian and domestic producers share equally in the annual market requirements. The Canadians obtain 100 percent of the increased market (100,000 Dth per day) resulting in their obtaining 20 percent of the total market. The total annual volume is the same as that used for Growth Assumption I (136,875,000 Dth).

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[3] The development of this factor is contained in associated work papers available upon request.

Scenario I - Commodity Price Based Market Sharing
Growth Assumption I

The Canadians, strictly due to the differential in the commodity changes are able to operate at a 100 percent load factor and thereby acquire 27 percent of the total annual market which reduces the domestic share from the present 75 percent load factor to 68.75 percent. With the loss of market share the domestic pipelines' commodity rate would increase.[4]

Scenario II - Commodity Price Based Market Sharing
Growth Assumption II

There is further growth in the Northeast market up to 800,000 Dth per day (a 100% increase). The Canadians, due to their low commodity charge, are able to capture all of the new market demand. With the Canadians operating at 100 percent load factor they acquire not only all of the annual growth but also 1/3 of the existing annual market requirements.[4]

These assumptions are reasonable if the Northeast customers purchase gas using a "least cost purchasing" policy. It is a very common practice for gas buyers, both for end-users and local distribution companies (LDC), when they have multiple sources of supply, to select the supplier with the lowest incremental cost. Such purchasing decisions are reviewed on a day-by-day basis. In the case of natural gas that decision will be based on the transportation commodity charge plus the volumetric wellhead charge

Case Cost Data

The following discussion contains a brief description of each of the nine cases we have studied and the sources of our data. The discrete cost data are set forth in Exhibit D and from published pipeline rates.

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[4] An additional policy consideration of the reduced load factor would be the shifting of the pipeline's fixed costs from Northeast markets to other more-captive markets (e.g. Georgia and the Carolinas) which are served by the Gulf Coast pipelines.

Case 1

- TransCanada's facility costs associated with the expansion of its system to serve the Northeast, for rate design purposes, are rolled-in with the costs of existing facilities.

Case 2

- TransCanada's facility costs associated with the expansion of its system to serve the Northeast, for rate design purposes, are treated on a stand alone or "incremental" basis.

The average unit costs are $1.69 (rolled-in) and $2.09 (incremental) for the transportation from Alberta to New York. For both cases 1 and 2, the percentages of variables and commodity costs of 12 and 21 percent, respectively are from page 16 of Exhibit B. These ratios represent the percentage of specific costs (variable and commodity) included in a particular pipeline's total average cost. By using these ratios it is possible to determine the unit fixed, variable, demand and commodity costs related to pipeline system being studied knowing its total unit cost. This then permits a valid comparisons without under taking a detailed cost of service study by using the data set forth on Exhibit D.

Case 3 (a, b and c)

- Domestic pipeline facility costs associated with expansion to serve the Northeast, for rate design purposes, are treated on a stand alone or "incremental" basis.

The three domestic producing basins shown on Exhibit D to be serving New York[5] were used to respond to this question. The unit costs for each basin contained in the support papers were used to develop the variable and commodity cost factors in these studies. These support papers identify the cost elements, the source of the cost elements and the pipelines are contained in the workpapers along with the development of variable and commodity cost factors.

One unique cost element in these Cases and in Cases 5 a,b and c is the cost associated with the pipelines' recovery of there take-or-pay (T-O-P) amounts. The misclassification of the fixed T-O-P amounts to the commodity sales and transportation rates also hinders the domestic producers from competing for gas markets.

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[5] Midcontinental, Arkoma and Gulf Coast.

Case 4

- Domestic pipeline facility costs associated with expansion to serve the Northeast, for rate design purposes, are rolled-in with the costs of existing facilities. Three traditional producing basins were considered.

This case was developed from data obtained from the Texas Gas/ CNG/ ANR/ Transco Joint Project. Certain assumptions were made to utilize these data as to capital structure, design load factor, debt and equity costs, and other cost of service elements to duplicate the results provided by the project sponsors. The average fixed costs were then adjusted to the 75 percent load factor assumption of these studies. The work paper showing the adjustment is contained, along with the project's material, in the workpaper package available upon request.

Case 5 (a,b and c)

- Domestic pipelines' existing facilities are used to deliver natural gas into the Northeast from the Gulf Coast. Three pipelines system were considered.

The transportation rates for the three pipeline systems [6] were obtained from the latest edition of the Zinder[7] rate book. The variable cost factors for Tennessee and Tetco were obtained for page 16 of Exhibit B. Transco's cost factor is assumed to be the same as Tennessee. One must be careful when using the results of these cases since they are based on the existing system's capacity and costs. The expansion of these particular pipelines would, on a rolled-in bases, increase the commodity rate level under the MFV.

Summary of Cases

The Table contained in the Executive Summary shows the significant results of each case. The first nine lines show the actual results in dollars per Dth. Lines 10 through 13 show the amount of the advantage that the Canadians have in the critical area of commodity charges when TransCanada's expansion costs are rolled in with its existing system costs.

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[6] Tennessee Gas Pipeline Company (Tennessee), Transcontinental Gas Pipeline Corporation (TRANSCO) and Texas Eastern Transmission Corporation (Tetco).

[7] 76th Edition - of the Summary of the Rate Schedules of Natural Gas Pipeline Companies, published by Zinder Companies, Inc. Washington D.C.

The difference in commodity charges is shown in columns c, e and g for the three scenarios. The advantage can be as high as $0.70. The Canadians have the advantage (i.e. lower rates) when the unit difference is in parentheses. Lines 14 through 18 show the Canadian's advantage with incremental pricing. The first three columns (a, b and c) present the Base Scenario average cost, variable cost and commodity charge results for each of the cases. Columns d and e present the average costs and commodity charge from Scenario I and the column f and g are from Scenario II. The variable costs (column b) apply equally to all three scenarios.

The Table also compares the Canadian Scenarios (Cases 1 and 2) with the same Scenarios for domestic pipeline systems. The increasing benefits that the Canadians enjoy in Scenario II (column g) over Scenario I (column e) and over the Base Scenario is attributable to the loss of annual load by the domestic pipeline systems as the Canadians acquire a greater percentage of the market. The short-term result is that domestic producers would have a 18-42 ¢ disadvantage in acquiring part of the growth market of the Northeast. In the long-term this disadvantage becomes even greater (38-68 ¢).

The Canadian unit amounts do not change between Scenarios I and II since these amounts are at a 100 percent load factor.

The commodity differential in the Base Scenario between Canadian and domestic gas shows that the Canadians have the competitive advantage of a rate design "tilt" regardless of whether the NEB adopts incremental or rolled-in pricing of the new Canadian facilities. A comparison of line 1, column e with lines 7, 8 and 9 of column c, shows the competitive advantage to Canadian gas when TransCanada/Iroquois operates at a 100% load factor. Even in the absence of a rate design advantage, given the shipper ownership in the Iroquois Project, the shippers have an economic interest in maximizing their utilization of Iroquois, which would encourage the shippers to use less domestic gas valley periods.

Conclusions

The economic feasibility of the Canadian projects to the Northeast are greatly effected by the existing differences in rate design methods between that employed by the NEB and the FERC. The short-term result is that domestic producers would have an 18-

42¢ disadvantage in acquiring part of the market growth in the Northeast. If both regulatory agencies employed the same methodology it would be extremely difficult to bring western Canadian gas supplies the 800 to 1,000 miles further than domestic suppliers to meet the increased demands of the Northeast.

Once the new Canadian facilities are installed the excess supplies in Canada will be dumped on the Northeast markets which will tend to drive down the price domestic producers can receive even further (38 - 68¢). This in turn will have a negative impact on the development of additional domestic natural gas supplies.

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 1 TransCanada/Iroquois Capacity with Rolled-in Rates Page 1 of 1

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 1.690	1
2	Variable Costs, per Dth			0.203	2
3	R-1 Charge, per Dth/d/Mo		$ 30.457		3
4	Commodity Charge, per Dth			0.355	4
5	100 % load factor Charge, per Dth			1.356	5
6	Cost of Service, ($000)	$ 46,264	$ 36,548	$ 9,715	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 1.268	7
8	Commodity Charge, per Dth			0.266	8
9	100 % load factor Charge, per Dth			30.723	9
10	Annual Quantity, MDth			36,500	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.268	11
12	Commodity Charge, per Dth			0.266	12
13	100 % load factor Charge, per Dth			30.723	13
14	Annual Quantity, MDth			146,000	14

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 2 TransCanada/Iroquois Capacity with Incremental Rates Page 1 of 1

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 2.090	1
2	Variable Costs, per Dth			0.251	2
3	R-1 Charge, per Dth/d/Mo		$ 37.666		3
4	Commodity Charge, per Dth			0.439	4
5	100 % load factor Charge, per Dth			1.677	5
6	Cost of Service, ($000)	$ 57,214	$ 45,199	$ 12,015	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 1.568	7
8	Commodity Charge, per Dth			0.329	8
9	100 % load factor Charge, per Dth			37.995	9
10	Annual Quantity, MDth			36,500	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.568	11
12	Commodity Charge, per Dth			0.329	12
13	100 % load factor Charge, per Dth			37.995	13
14	Annual Quantity, MDth			146,000	14

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 3a with Midcontinent Supplies

Page 1 of 3

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 1.291	1
2	Variable Costs, per Dth			0.298	2
3	R-1 Charge, per Dth/d/Mo		$ 15.459		3
4	Commodity Charge, per Dth			0.614	4
5	100 % load factor Charge, per Dth			1.122	5
6	Cost of Service, ($000)	$ 141,401	$ 74,201	$ 67,200	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 1.409	7
8	Commodity Charge, per Dth			0.669	8
9	100 % load factor Charge, per Dth			1.178	9
10	Annual Quantity, MDth			100,375	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.937	11
12	Commodity Charge, per Dth			0.921	12
13	100 % load factor Charge, per Dth			1.429	13
14	Annual Quantity, MDth			73,000	14

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 3b with Arkoma Supplies Page 2 of 3

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 1.173	1
2	Variable Costs, per Dth			0.283	2
3	R-1 Charge, per Dth/d/Mo		$ 12.433		3
4	Commodity Charge, per Dth			0.628	4
5	100 % load factor Charge, per Dth			1.037	5
6	Cost of Service, ($000)	$ 128,480	$ 59,678	$ 68,802	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 1.280	7
8	Commodity Charge, per Dth			0.685	8
9	100 % load factor Charge, per Dth			1.094	9
10	Annual Quantity, MDth			100,375	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.760	11
12	Commodity Charge, per Dth			0.942	12
13	100 % load factor Charge, per Dth			1.351	13
14	Annual Quantity, MDth			73,000	14

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 3c with Gulf Coast Supplies

Page 3 of 3

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 1.152	1
2	Variable Costs, per Dth			0.294	2
3	R-1 Charge, per Dth/d/Mo		$ 13.340		3
4	Commodity Charge, per Dth			0.567	4
5	100 % load factor Charge, per Dth			1.005	5
6	Cost of Service, ($000)	$ 126,089	$ 64,034	$ 62,055	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 1.256	7
8	Commodity Charge, per Dth			0.618	8
9	100 % load factor Charge, per Dth			1.057	9
10	Annual Quantity, MDth			100,375	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.727	11
12	Commodity Charge, per Dth			0.850	12
13	100 % load factor Charge, per Dth			1.289	13
14	Annual Quantity, MDth			73,000	14

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 4 Domestic Capacity with Incremental Rates

Page 1 of 1

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 1.129	1
2	Variable Costs, per Dth			0.172	2
3	R-1 Charge, per Dth/d/Mo		$ 15.026		3
4	Commodity Charge, per Dth			0.471	4
5	100 % load factor Charge, per Dth			0.965	5
6	Cost of Service, ($000)	$ 123,647	$ 72,124	$ 51,523	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 1.232	7
8	Commodity Charge, per Dth			0.513	8
9	100 % load factor Charge, per Dth			1.007	9
10	Annual Quantity, MDth			100,375	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.694	11
12	Commodity Charge, per Dth			0.706	12
13	100 % load factor Charge, per Dth			1.200	13
14	Annual Quantity, MDth			73,000	14

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 5a with Tennessee Gas Pipeline Company's Existing Rates

Page 1 of 3

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 0.644	1
2	Variable Costs, per Dth			0.097	2
3	R-1 Charge, per Dth/d/Mo		$ 3.560		3
4	R-2 Charge, per Dth/Mo		0.121		4
5	Commodity Charge, per Dth			0.367	5
6	100 % load factor Charge, per Dth			0.605	6
7	Cost of Service, ($000)	$ 70,557	$ 30,359	$ 40,197	7
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
8	Average Costs, per Dth			$ 0.703	8
9	Commodity Charge, per Dth			0.400	9
10	100 % load factor Charge, per Dth			0.639	10
11	Annual Quantity, MDth			100,375	11
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
12	Average Costs, per Dth			$ 0.967	12
13	Commodity Charge, per Dth			0.551	13
14	100 % load factor Charge, per Dth			0.789	14
15	Annual Quantity, MDth			73,000	15

Iroquois Project-Impact of Rate Design on Domestic Producers

Case 5b with Transcontinental Gas Pipe Line Corporation's Existing Rates

Page 2 of 3

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 0.809	1
2	Variable Costs, per Dth			0.121	2
3	R-1 Charge, per Dth/d/Mo		$ 12.040		3
4	Commodity Charge, per Dth			0.281	4
5	100 % load factor Charge, per Dth			0.677	5
6	Cost of Service, ($000)	$ 88,561	$ 57,792	$ 30,770	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 0.882	7
8	Commodity Charge, per Dth			0.307	8
9	100 % load factor Charge, per Dth			12.347	9
10	Annual Quantity, MDth			100,375	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.213	11
12	Commodity Charge, per Dth			0.422	12
13	100 % load factor Charge, per Dth			12.462	13
14	Annual Quantity, MDth			73,000	14

Iroquois Project-Impact of Rate Design on Domestic Producers
Case 5c with Texas Eastern Transmission Corporation's Existing Rates

Page 3 of 3

Line No.	Description (a)	Total (b)	Demand (c)	Commodity (d)	Line No.
	Base Scenario - Proportional Market Sharing-Growth Assumption I				
1	Average Costs, per Dth			$ 0.743	1
2	Variable Costs, per Dth			0.201	2
3	R-1 Charge, per Dth/d/Mo		$ 9.350		3
4	Commodity Charge, per Dth			0.333	4
5	100 % load factor Charge, per Dth			0.641	5
6	Cost of Service, ($000)	$ 81,387	$ 44,880	$ 36,507	6
	Scenario I - Commodity Price Based Market Sharing-Growth Assumption I				
7	Average Costs, per Dth			$ 0.811	7
8	Commodity Charge, per Dth			0.364	8
9	100 % load factor Charge, per Dth			9.714	9
10	Annual Quantity, MDth			100,375	10
	Scenario II - Commodity Price Based Market Sharing-Growth Assumption II				
11	Average Costs, per Dth			$ 1.115	11
12	Commodity Charge, per Dth			0.500	12
13	100 % load factor Charge, per Dth			9.850	13
14	Annual Quantity, MDth			73,000	14

Iroquois
GAS TRANSMISSION SYSTEM

ONE CORPORATE DRIVE, SUITE 606 · SHELTON, CT 06484
(203) 926-1555 · FAX (203) 929-9501

June 1, 1990

Honorable J. Bennett Johnston
Chairman
Senate Committee on Energy and Natural Resources
SD-364
Washington, D.C. 20510

RE: Iroquois Gas Transmission System --
Additional Submissions for the Record
of the May 3, 1990 Committee Hearing

Dear Mr. Chairman:

Enclosed herewith are additional documents which address certain issues raised during the May 3, 1990 Committee hearing on the Iroquois Gas Transmission System ("Iroquois"). Iroquois respectfully requests that these documents be made part of the record of the hearing, along with this letter which explains their relevance. Iroquois' Chairman, Mr. Joseph E. Ramsey, has received your May 14, 1990 letter requesting written responses to three questions. Those responses are being provided under separate cover.

The documents enclosed herewith and their relevance are as follows:

1. Letter from Senators Kennedy, Kerry and Lautenberg to Chairman Allday: On May 2, 1990 Senators Kennedy, Kerry and Lautenberg wrote to Federal Energy Regulatory Commission ("FERC") Chairman Allday stressing the importance of expeditious action on the remaining "Open Season" projects so that additional gas supplies -- domestic and Canadian -- will be available to the Northeast over the next several years.

2. Letters Supporting Iroquois Process: Pursuant to our discussions with your staff, I enclose a complete set of the letters written in connection with the hearing which support timely certification of Iroquois. Staff asked that we forward these documents in order to verify that the Committee's hearing record is complete. These letters are from various gas industry

trade associations, state regulatory and elected officials, and distribution companies in the Northeast. These letters illustrate the very broad public support that exists for certification of the Iroquois project.

3. Letter from Chairman Allday to Chairman Philip R. Sharp: On April 9, 1990, FERC Chairman Allday responded in writing to a request from Chairman Sharp for information regarding, among other things, the relative shares of domestic and Canadian gas involved in the various projects which emerged from the FERC Northeast Open Season proceeding. Chairman Allday's letter points out that 53.5% of the gas involved in Open Season projects was domestic, and 46.5% was Canadian. Attached to Chairman Allday's letter is a two page table listing the Open Season projects.

Chairman Allday's letter refutes the Independent Petroleum Association of America's ("IPAA's") assertions, made in their written hearing testimony ("IPAA Testimony") and orally during the hearing, that the Open Season proceeding and FERC policies have favored Canadian over domestic gas. It also refutes IPAA's assertion, at page 17 of the IPAA Testimony, that "the newest Northeast projects are primarily Canadian-supplied." Finally, it refutes IPAA's assertions that "FERC [has failed] to permit IPAA and other parties to present evidence . . . to show that cheaper domestic alternatives exist" [IPAA Testimony, page 2] and that the Canadian-supplied Open Season projects will have "devastating consequences for U.S. producers currently serving those [Northeast] markets." Id.

4. Final Report of Chief Judge and Certification of Settlement: On November 30, 1988, FERC Chief Administrative Law Judge Curtis L. Wagner, Jr. issued his final report on the Open Season settlement process. Chief Judge Wagner also certified the final Open Season settlement (involving, among others, the Iroquois project) to the full Commission. Included in the Report is a detailed description of how the Open Season settlement involved the participation of the market and indeed was driven by market forces. See Final Report, pages 4-5.

The Final Report indicates that IPAA's desire that "the market . . . decide whether to purchase domestic or Canadian natural gas" [IPAA Testimony, pages 8-9] was in fact satisfied by the market-driven Open Season settlement process. (IPAA ultimately concedes, at page 22 of the IPAA Testimony, that "The contested settlement reached in the open-season proceeding permitted the parties to elect among the various projects, with each sponsor filing a new application for a resized facility based upon the resulting customer commitments.")

5. Correspondence Between IPAA and Northeast Gas Markets, Inc. Regarding Proposed Contractual Arrangements: In 1988, Northeast Gas Markets, Inc. ("NEGM"), an organization formed to identify diverse gas supply opportunities for its twenty-four Northeast local distribution company ("LDC") members, initiated formal discussions with IPAA for the specific purposes of developing an acceptable basis for gas supply transactions between NEGM and IPAA members. The discussions involved formal meetings and a specific and detailed contract proposal by NEGM for firm, long-term direct purchases by Northeast LDCs. A specific chronology of the discussions is included with the various letters and contract drafts attached.

Notwithstanding this concerted effort by NEGM, IPAA repeatedly failed to respond to specific, detailed proposals. Ultimately, the NEGM program was suspended due to the lack of cooperation by IPAA.

The attached documents directly rebut IPAA's statements that "domestic natural gas would provide for all reasonably projected base-load needs in the Northeast" [IPAA Testimony, page 9] and contradict the IPAA Chairman's May 3, 1990 oral testimony that he was unaware of any proposals by Northeast LDCs to purchase domestic gas on terms equivalent to purchases of Canadian gas.

On this same point, I would also direct your attention to the May 1, 1990 letter to you from Paul W. Gromer, Commissioner of the Massachusetts Division of Energy Resources, which is already in the record of this proceeding. Mr. Gromer's letter summarizes very well the opportunities available for domestic gas in the Northeast, indicating that Mr. Hilliard's concerns over unfair displacement of domestic gas are ill-founded.

6. Summary of IPAA Pleadings In FERC and DOE Proceedings Relating to Iroquois: In the period July 26, 1988 to February 12, 1990, IPAA filed thirteen pleadings in FERC and DOE proceedings relating directly or indirectly to the Iroquois project. Several of those pleadings involved evidentiary submissions, including the expert study prepared by Prather Energy Consultants, Inc. ("Prather Study") which is appended to the IPAA Testimony as

Exhibit B. Those submissions are part of the record of the FERC and DOE proceedings.

The attached summary of IPAA pleadings demonstrates that IPAA has not been denied "an opportunity to place into evidence the expert testimony which we believe proves that domestic producers are disadvantages by current DOE and FERC policies." IPAA Testimony, page 8.

7. Iroquois' Response to Prather Study: On February 22, 1989, IPAA filed the Prather Study with the FERC. On May 8, 1989, the Prather Study was filed with DOE's Office of Fossil Energy. In both of those filings and in the IPAA Testimony, IPAA represented that the Prather Study "irrefutably demonstrates the unfairness of the rate structures proposed by the Northeast project sponsors." IPAA Testimony, page 6. However, the Prather Study does no such thing. On March 9, 1989, Iroquois responded to the Prather Study in a pleading filed with the FERC in the Iroquois proceeding. The relevant portions of that pleading are attached and point out that:

> [T]he clear focus of the Prather Study is not on the Iroquois project per se, but on what IPAA and the Prather Study see as fundamental problems in the way in which the Commission continues to regulate U.S. pipelines, especially pipelines performing a merchant function. While a small portion of the Prather Study is devoted to a discussion of Canadian ratemaking policies (which the Prather Study seems to endorse), the only point made by the Prather Study is that the policies are different, with Canadian pipelines permitted to include more of their fixed costs in the demand component of their tolls. What the . . . Prather Study [does] not demonstrate . . . is that the different policies in fact result in competitive advantages for Canadian gas under the circumstances relevant to the Iroquois application.[1]

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[1] The FERC has also concluded that the IPAA position, which the Prather Study purports to endorse, is without merit to the extent that it asserts an inherent competitive advantage for Canadian gas. See Tennessee Gas Pipeline Company, et al., Docket Nos. CP88-171-000, et al., Order Issuing Certificates (May 2, 1990), at pages 32-36 [the so-called "NIPS Phase II Order"].

8. Letter from C.G. Edge to Chairman Johnston: In its Testimony at page 7, IPAA invokes the name of the former chairman of Canada's National Energy Board ("NEB"), C. Geoffrey Edge, implying that Mr. Edge supports the proposition that "the rate structures of these projects in Canada will squeeze-out competitively priced domestic gas to the extent necessary to assure full utilization of the new facilities." Mr. Edge's pointed response rejecting IPAA's effort to associate him with IPAA's position is contained in a May 2, 1990 letter to you, a copy of which is appended hereto for the record.

Mr. Edge's May 2 letter also serves to refute the notion, advanced by IPAA in its Testimony at page 9, that equalization of rate designs in Canada and the U.S. will obviate the need for base-load Canadian gas supplies. Mr. Edge properly points out that competitiveness of Canadian and U.S. gas supplies is a function of many things, not just transportation rate designs.

9. Department of Energy Letter to IPAA Counsel Returning Rehearing Application: On February 12, 1990, IPAA filed an application with DOE seeking rehearing of Opinion and Order No. 368 conditionally authorizing importation of certain Canadian gas to be transported on Iroquois. On March 9, 1990, DOE's Office of Fossil Energy returned IPAA's rehearing application. DOE explained that:

> Since no natural gas may be imported under Order 368, and DOE intends to reexamine the preliminary findings made in that order prior to reaching any final decision, rehearing of Order 368 is premature. Accordingly, IPAA's . . . application for rehearing is being returned to you. All parties will have an opportunity to request rehearing upon a final determination on the . . . applications by the DOE.

DOE's letter refutes IPAA's assertion that DOE returned its rehearing application because it was "improper." IPAA Testimony, page 11. Despite IPAA's inferences to the contrary, DOE has denied no rights afforded to IPAA by law, rule or regulation.

10. FERC 1987 Order Affirming Initial Decision in Boundary Gas, Inc., Docket No. RP 85-112-000: In 1987, several independent domestic gas producer associations (not including

IPAA) intervened in a FERC proceeding involving Boundary Gas, Inc. ("Boundary"), an entity created by several Northeast LDC's to import Canadian gas. A primary issue in the case was whether the principles of FERC Opinion No. 256 should apply to the Boundary transaction in order to avoid a competitive advantage for Canadian gas. After an evidentiary hearing, the FERC concluded in the attached Order that, because the Boundary transactions were functionally and legally equivalent to direct purchases of Canadian gas by LDC's (with one exception involving an interstate pipeline subsidiary of an LDC), no purpose would be served by applying Opinion No. 256 to the Boundary transactions.

The Boundary project was the precursor of the Alberta Northeast Gas Limited ("ANE") project, which involves the greatest quantity of Canadian gas to be transported on the Iroquois pipeline. ANE is a Canadian, rather than a U.S. company but, like Boundary, selling directly to seventeen LDCs. Thus, the functional and legal effects of the Boundary and ANE transactions are, and are intended to be, the same.

The attached FERC Order rebuts the claim by IPAA [Testimony, pages 15-16] that, in contrast to Boundary, ANE was formed "so as to avoid a jurisdictional sale for resale within the United States . . . [and] to avoid fair and equal treatment for Canadian and domestic costs and to take advantage of the difference in rate design methodologies used in Canada and the United States." The principles of FERC Opinion No. 256 do not apply to either Boundary or ANE transactions with LDC's for the same reason -- both projects involve direct purchases of gas by state-regulated LDC's from Canadian suppliers and not from FERC-regulated interstate merchant pipelines. The purchasing LDC's are thus not subject to the allocation of Canadian costs in pipeline sales rates which Opinion No. 256 found to be unfair.[2]

In addition to providing the documents referenced above, Iroquois wishes to respond on the record to five misstatements of fact in IPAA Testimony. First, at page 5 of the Testimony, IPAA states:

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[2] The IPAA Testimony, at page 19, incorrectly states that "Opinion No. 256 addressed a competitive advantage conferred on imported gas as a result of the rate design used in Canada." The attached FERC Order in the Boundary proceeding accurately summarizes the Commission's holdings in Opinion No. 256.

> Absent FERC approval by August 1, 1990, the producers in Alberta have a right to vote again on whether to supply the Iroquois volumes.

That is incorrect. The August 1989 Alberta producer vote approving volumes proposed to be purchased by LDC's from two Canadian supply "pools" (viz., Western Gas Marketing Limited and ProGas Limited) for transportation on Iroquois was not conditioned on FERC certification of Iroquois by August 1, 1990. The need for timely FERC approval relates to the fact that, to be in service by November 1, 1991, Iroquois must complete its financing and purchase essential property rights and equipment in the second half of 1990. If Iroquois is unable to achieve its November 1, 1991 in-service date, NEB licences to export a substantial portion of volumes to be transported on Iroquois may expire. Expiration of those licences may require renegotiation of the supply contracts with Western Gas Marketing Limited and ProGas Limited, which in turn could necessitate an additional Alberta producer vote with regard to those supplies.

Second, at pages 5 and 23 of its Testimony, IPAA asserts that the $2.6 billion cost of the currently proposed TransCanada expansion was unknown at the time of the Open Season proceeding or the DOE conditional authorization of the ANE imports. IPAA also asserts that 90% of the TransCanada expansion "is dedicated to serving Iroquois . . . ." Those statements are incorrect. To begin with, the $2.6 billion figure cited by IPAA is in Canadian dollars; the U.S. dollar equivalent is approximately $2.1 billion. Furthermore, 69% (not 90%) of the proposed TransCanada expansion costs relate to volumes proposed to be shipped on Iroquois; the balance relates to volumes for the domestic Canadian market. IPAA's reference at page 23 to $1.2 billion (presumably Canadian dollars) in TransCanada costs (which IPAA contrasts to the current $2.6 billion in costs) ignores the fact that $1.1 billion (U.S.) in costs were then proposed for expanding the facilities of Great Lakes Gas Transmission Co. as the means of creating capacity to serve Eastern Canadian and Northeast markets in 1991. TransCanada now proposes to construct all new capacity for 1991 on its northern line, not partially on the Great Lakes system. Thus, the Can $1.2 billion cost did not "escalate" to Can $2.6 billion; Great Lakes costs are simply included now in the U.S. $2.1 billion TransCanada costs. Finally, and most importantly, the projected costs for TransCanada facilities to serve the Iroquois export point were in fact known and were in fact revealed during the Open Season proceeding and have not changed materially since then.

Third, at page 17 of its Testimony, IPAA states that "the only party never to have its equity position [in Iroquois] diluted was TransCanada." A simple review of Iroquois' original 1986 application and its January 1989 post-Open Season application would have revealed to IPAA that TransCanada's equity interest in Iroquois decreased from 50% in 1986 to 29% in 1989.

Fourth, at pages 4 and 5 of its Testimony, IPAA refers to proposals that the cost of the TransCanada facilities expansion be "rolled in" to TransCanada's rate base as proposals "to force Canadian consumers to subsidize Iroquois." IPAA fails to note that "rolled in" rates have been the standard practice in Canada and the U.S. for many years. The function of "rolled-in" rates is to insulate all pipeline customers from the cyclical costs of pipeline expansions. Indeed, departing from that rate methodology would confer an advantage on existing TransCanada ratepayers, not vice versa as IPAA suggests.

Finally, at page 22 of its Testimony, IPAA states:

> [A] key element in assessing the "public convenience and necessity" of a pipeline construction project is . . . a determination as to whether the netback prices at the wellhead will attract gas supplies to the project. Neither FERC nor DOE has performed an objective analysis of [this] crucial [issue].

What IPAA apparently has missed completely is the fact that the supply contracts for the volumes to be transported on Iroquois are either directly with Canadian producers or with supply "pools" which have already received producer approval for the sales. Thus, Canadian gas supplies have already been "attracted" to the project -- an objective fact specifically noted by DOE in its conditional Order No. 368 and which the FERC will presumably take into account in considering certification of Iroquois.

We appreciate this opportunity to provide additional documents and factual information for the record of the May 3, 1990 hearing.

Very truly yours,

Robert J. Reid

Enclosures

WARD M. KENNEDY
MASSACHUSETTS

ATTACHMENT 1

United States Senate
WASHINGTON, DC 20510-2101

May 2, 1990

Honorable Martin Allday
Chairman
Federal Energy Regulatory Commission
825 North Capitol Street
Washington, D.C. 20426

Dear Chairman Allday:

We have learned that you have been asked to testify before the Senate Committee on Energy and Natural Resources this week on issues related to the introduction of Canadian gas supplies into United States markets, particularly in the Northeast.

While we are not members of the Committee, we wanted you to know how appreciative we have been of the actions taken by the FERC over the past three years to process the approval of facilities that will bring new gas supplies to the Northeast region. The "Open Season" process has already resulted in significant new capacity from domestic sources to fuel the region's energy requirements but still more supplies are needed.

We strongly support the continued efforts of the Commission under your leadership to bring new gas supplies to the region. We know that you are well aware of the deep level of concern in the Congress and nationwide about environmental protection. As we seek to fashion legislation that will improve the quality of the air we breathe, we are also conscious of the need for timely new sources of energy, especially for electric generation, to serve the Northeast region's economy. In light of these two critically important goals, we strongly support your continuing actions to ensure that additional sources of this clean fuel -- both domestic and Canadian -- will be available to the Northeast over the next several years.

Sincerely,

Edward M. Kennedy
Edward M. Kennedy

John F. Kerry
John F. Kerry

Frank Lautenberg
Frank R. Lautenberg

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P O Box 2511
Houston, Texas 77252
(713) 757-2131

April 3, 1990

Chairman Martin Allday
Commissioners Charles A. Trabandt,
Jerry J. Langdon and Elizabeth
A. Moler
Federal Energy Regulatory Commission
825 North Capitol Street, N. E.
Washington, D. C. 20426

Re: Tennessee Gas Pipeline Company
Docket No. CP88-171-001
(Niagara Import Point Settlement)

Dear Chairman Allday and Commissioners Trabandt,
Langdon and Moler:

Despite numerous entreaties from pipeline applicants and customers needing service, the Commission has failed to discuss or take action on certification of the initial 31.4 mile Spur Loop Line phase of the Niagara Import Point Settlement Project (NIPS). The NIPS item was last struck from the Commission agenda in apparent response to a March 13, 1990 letter from the Independent Producers Association of America and the Texas Independent Producers and Royalty Owners Association (IPAA/TIPRO) alleging that differences in Canadian and United States pipeline rate design policies give Canadian gas a competitive advantage over domestic gas.

Tennessee Gas Pipeline Company (Tennessee) writes once more to strongly urge the Commission to act on this project immediately, by notational vote if possible, and in any event no later than its next scheduled meeting on April 11, 1990. Further, because the Commission may have been influenced by IPAA/TIPRO's position that rate design will adversely affect domestic producers' ability to compete with Canadian producers, Tennessee shows below that, in the circumstances of this case, the alleged competitive edge to Canadian gas does not exist, at least as far as pipeline rates are concerned.

The Need for Immediate Action. Tennessee has repeatedly explained why the timing of certification of the initial (31.4 mile) phase of the Niagara Import Point Settlement project is critical to Tennessee, to other NIPS applicants, and to their customers. Most recently, in his February 28 letter to you, Tennessee's President, Robert C. Thomas, noted that Commission action was required by the March 14, 1990 meeting if Tennessee was to avoid incurring significant costs and cancellation charges that would be wasteful "sunk" costs if the NIPS facilities were ultimately constructed. With the Commission's delay, Tennessee has already incurred some of these costs and is still determining whether and how much of the remainder can be avoided if Commission action is taken by April 11.

Mr. Thomas' letter focused on Tennessee's efforts to avoid construction of compression to provide firm already-certificated services, and to obtain certification of the more cost-effective NIPS facilities design. With the advent of spring, Tennessee is now also becoming concerned about its ability to construct this year the full 31.4 mile Niagara loop segment without regard to the "avoided" compression. Given the need to obtain eminent domain for certain tracts, complexities in the New York state permitting process, and the physical time required to lay 30" pipeline in over 30 miles of right-of-way, Tennessee can afford little additional delay if it is to be able to get facilities in-service before the end of 1990.

Moreover, customers anticipating service through NIPS facilities have already made financial commitments far exceeding the total cost of associated gas pipeline facilities -- one cogeneration customer alone, Altresco, has already spent over $150 million to construct its power plant while awaiting Commission action. These customers, too, deserve to know whether the Commission is prepared to certify the initial phase of the NIPS project at its April 11 meeting -- or will instead advise NIPS applicants and customers that additional gas service will not be available to serve Northeast markets in 1990 and that they should act accordingly.

Rate Design Tilt, Commodity Rates, and Competition. IPAA/TIPRO's competitive concern in this proceeding arises from the fact that Canadian regulatory authorities utilize a full "fixed-variable" ("FV") rate design for tolls on Canadian gas pipelines, whereas the FERC currently requires that most U.S. gas pipeline rates be derived using a "modified-fixed variable" or "MFV" rate design. The MFV rate design is the same as the FV rate design except that a pipeline's equity return and related taxes is shifted from the demand component into the commodity component of the pipeline's rates. As a result, with cost of service and other factors of rate design held constant, a U.S.

MFV rate design would have lower demand components, and higher commodity components, than a Canadian FV rate design. In other words, a U.S. firm domestic producer/shipper would pay relatively less to reserve firm capacity than a Canadian producer/shipper; at the same time, a U.S. firm domestic producer/shipper would pay relatively more to use his reserved capacity (because some fixed costs are in the commodity rate) than his Canadian counterpart.

IPAA/TIPRO argue that this difference in rate designs give Canadian producers a competitive advantage. Specifically, they argue that demand charges are "sunk" costs and hence competitively irrelevant 1/ and that Canadian producers have a competitive edge because a U.S. producer pays a higher absolute commodity rate to transport gas to market. Tennessee submits that in this case, indisputable facts demonstrate that IPAA/TIPRO's premise is not supportable: the commodity charges faced by Canadian producers are roughly equivalent to or even significantly greater than the charges faced by domestic producers.

Because all relevant rates (both present and proposed) for Canadian and U.S. gas transportation are public and on file, it is possible to make a direct comparison between commodity rates faced by Canadian and domestic producers to market gas in competition with the initial NIPS project. Canadian volumes in the initial phase of the NIPS project must pass through NOVA, TransCanada, and the relevant U.S. pipeline (National Fuel/Transco for the TEMCO volumes; Tennessee for the Altresco volumes) to get to market, and must pay the commodity component of each of these pipelines' rates, plus fuel retention for each pipeline. U.S. domestic volumes can flow through various routes to get to the same market; again, shippers must pay the commodity component of these rates plus fuel retention.

As more fully set forth in the Appendix, the total commodity cost (including fuel) applicable for movement of the Canadian TEMCO volumes, as proposed in the initial phase of the NIPS

1/ Tennessee submits that in a competitive world it is not always better to pay high demand charges to reserve capacity than to pay for capacity as you go. Clearly, not all producer/shippers desire to risk increased fixed obligations in order to reduce variable costs of unit sales.

project, is over 40 U.S. cents delivered to the TEMCO customers (Long Island Lighting Company, Baltimore Gas and Electric Company, and Public Service Electric and Gas Company). By contrast, the commodity rate on Tennessee, Transco or Texas Eastern (Tetco) for firm transportation services from domestic supplies in Texas/Louisiana to these same customers range from 19 U.S. cents to 27 U.S. cents depending on the pipeline involved and the distance traveled. 2/

Similarly, the total commodity cost (including fuel) applicable for movement of Canadian volumes to Altresco's cogeneration plant in Pittsfield, Massachusetts, as proposed in the NIPS project, is 22 U.S. cents. (The commodity cost is significantly lower for the Altresco volumes than for the TEMCO volumes because the only commodity cost in Tennessee's proposed service from the U.S. border at Niagara to Altresco's plant arises from fuel and losses.) 3/ As shown in the Appendix, the

---

2/ As TEMCO and its customers have explained in their February 26, 1990 letter, IPAA/TIPRO's rate design "tilt" concerns are irrelevant to the services proposed for TEMCO also because the contracts between TEMCO and its customers are based upon a two part demand/commodity payment structure. These contracts are on file and publicly available at, and have been approved by, the Department of Energy (DOE/FE Opinion and Order No. 338, October 10, 1989). Moreover, these pricing provisions cannot be changed in any significant manner without another DOE proceeding -- in which IPAA/TIPRO is free to participate -- for an amendment of the import authorization.

3/ U.S. producers obtain a commodity cost competitive advantage -- rather than mere comparability -- on markets served by Tennessee if the Commission rejects Tennessee's request for a single part demand charge rate design. For example, if the Commission required a commodity rate for services to Altresco equal to Tennessee's current generally applicable 100% load factor IT rate from Niagara to Altresco, the delivered commodity rate to Altresco's plant would increase by approximately 11.3 U.S. cents, to 33.3 U.S. cents. This commodity rate approaches the undiscounted IT rate on Tennessee to Altresco's plant from domestic sources -- 36.9 U.S. cents plus 6.1% fuel. As Tennessee has explained in numerous pleadings in this proceeding, however, a two-part rate design is not appropriate for the incremental services proposed here.

maximum commodity cost of firm transportation for domestic producers to Altresco's plant on Tennessee is also 22 U.S. cents.

Thus, the commodity cost faced by domestic shippers for firm transportation through existing facilities is equal to or far lower than that faced by Canadian shippers for firm transportation service through the facilities proposed in the initial phase of the NIPS project. The NIPS settlement provides for new transportation service for domestic gas supplies as well, to serve projects which have been developed by ANR Cogeneration in Connecticut and Massachusetts. The proposed commodity cost faced by the NIPS domestic shippers for incremental firm transportation -- 9.2 U.S. cents -- is also less than the minimum 22 U.S. cent commodity cost applicable to incremental firm transportation of Canadian gas from Alberta to shippers served by the NIPS project.

Conclusion. Tennessee Gas Pipeline, which delivers over 3 billion cubic feet of domestic gas to its markets *daily*, is very concerned at what seems to be the ability of domestic independent producer groups to frustrate FERC action on this Canadian import project. The NIPS project is for transportation service only -- facilities will be installed to deliver supplies under private contracts negotiated between willing Canadian sellers and willing U.S. customers.

As pointed out to you in the March 30, 1990 letter from Howard Lutz, President of Altresco, the willingness of Canadian producers to enter *firm*, *long-term* gas supply contracts were the key to these new contractual arrangements, not theoretical rate design advantages; and as we have shown above, the facts do not support the theory.

Tennessee reiterates its request that the Commission take prompt action to approve the initial phase of the NIPS project.

Respectfully submitted,

TENNESSEE GAS PIPELINE COMPANY

By Joseph E. Ramsey
Joseph E. Ramsey

cc: All Parties of Record

Exhibit A
Page 1 of 3

TENNESSEE GAS PIPELINE COMPANY

COMMODITY RATES FACED BY PRODUCERS TO TRANSPORT GAS TO MARKET

CANADIAN PRODUCERS			TEMCO	ALTRESCO
NOVA	Transportation	1/	$0.0056	$0.0056
	Fuel (.75%)	2/	$0.0110	$0.0110
TransCanada	Transportation	3/	$0.0669	$0.0669
	Fuel (7.4%)	2/	$0.1110	$0.1110
National Fuel	Transportation	4/	$0.1031	N/A
	Fuel (2%)	2/	$0.0300	N/A
Transco	Transportation	5/	$0.0822	N/A
Tennessee	Fuel (1.7%)	2/	N/A	$0.0255
	TOTAL		$0.4098	$0.2200
DOMESTIC PRODUCERS				
Tennessee FT	Transportation	6/	$0.1308	$0.1308
	Fuel (6.1%)	2/	$0.0915	$0.0915
	Total Tennessee (>1200 miles)		$0.2223	$0.2223
Transco FT	Transportation	6/	$0.1040	
	Fuel (5.7%)	2/	$0.0855	
	Total Transco		$0.1895	
Tetco FT	Transportation	7/	$0.2068	
	Fuel (4%)	2/	$0.0600	
	Total Tetco		$0.2668	

Exhibit A
Page 2 of 3

TENNESSEE GAS PIPELINE COMPANY

COMMODITY RATES FACED BY PRODUCERS PURSUANT TO NIPS APPLICATION

DESCRIPTION			CANADIAN SUPPLY ALTRESCO	DOMESTIC SUPPLY COGEN PROJECTS
NOVA	Transportation	1/	$0.0056	N/A
	Fuel (.75%)	2/	$0.0110	N/A
TransCanada	Transportation	3/	$0.0669	N/A
	Fuel (7.4%)	2/	$0.1110	N/A
Tennessee	Fuel (Altresco - 1.7%; ANR - 6.1%)	2/	$0.0255	$0.0915
	TOTAL		$0.2200	$0.0915

Exhibit A
Page 3 of 3

TENNESSEE GAS PIPELINE COMPANY

FOOTNOTES

1/ See NOVA's tariff, attached

$Can	$0.0066	/Mcf
Exchange Rate	1.1780	
$U.S.	$0.0056	/Mcf

2/ Fuel retention is conservatively valued at $1.50 U.S./Mcf. Because fuel retention is greater for Canadian supplied volumes, increases in gas prices would aid U.S. producers vis-a-vis Canadian producers. See attached letter for NOVA fuel rates.

3/ See TCPL's tariff, attached

Canadian Rate	$2.7820	$/10^3m^3$
Convert to Mcf	0.02832784	
$Can	$0.0788	/Mcf
Exchange Rate	1.1780	
$U.S.	$0.0669	/Mcf

4/ Per National Fuel's Supplement to Amended Application, Docket No. CP88-94-001

5/ Per Transco's Supplement to Application, Docket No. CP88-92-000

6/ Per current effective tariff

7/ Per Tetco's Docket No. RP88-67 Stipulation & Agreement, as amended, approved by the Commission February 23, 1990

NOVA Corporation of Alberta
ALBERTA GAS TRANSMISSION DIVISION - TRANSPORTATION RATES
For The 12 Months Commencing November 1, 1989

Description	Total Costs $000'S	Less Other Services $000'S	Transportation Cost of Service $000'S	Less Interruptible Revenue $000'S	Firm Service Revenue Requirement $000'S	Fixed Costs $000'S	Variable Costs $000'S
Variable Costs	$9,500	$77	$9,423	$742	$8,681	$0	$8,681
Operating & Maintenance	160,274	1,305	158,969	12,515	146,454	146,454	0
Depreciation	84,858	691	84,167	6,626	77,541	77,541	0
Municipal Taxes	33,420	272	33,148	2,610	30,538	30,538	0
Income Taxes	29,255	238	29,017	2,284	26,733	26,733	0
Return on Rate Base	217,106	1,768	215,338	16,952	198,386	198,386	0
Sub-total	$534,413	$4,361	$530,082	$41,729	$488,333	$479,652	$8,681
Transportation by Others	86,932	0	86,932	6,844	80,088	73,364	6,724
TOTAL	$621,345	$4,361	$616,994	$48,573	$568,421	$553,016	$15,405

Volumes	10-6m3/day	10-6m3	BCF/Day	BCF
Total Receipt Contract Demands	397.6		14.1	
Total Delivery Contract Demands	227.6		8.1	
Total FS Contract Demand Quantity	625.2		22.2	
Total FS Receipt Volume		66,015.0		2,343
Total IT-1 Receipt Volume		4,225.0		150
Total IT-2 Receipt Volume		7,050.0		250
Total IT-2 Delivery Volume		5,600.0		199

Rates	$/10-3m3	$/10-3m3	$/mcf	cents/mcf
FS Demand Rate per Month	$73.75		$2.08	
FS Commodity Rate		$0.23		0.66
IT-1 Interruptible Rate		$3.55		10.00
IT-2 Interruptible Rate		$2.65		7.50
TS Transitional Rate		$0.53		1.50

NOVA
ALBERTA GAS TRANSMISSION DIVISION

NOVA Corporation of Alberta
Alberta Gas Transmission Division
P.O. Box [illegible], Station M
Calgary, Alberta
Canada T2P [illegible]
Offices: 801 Seventh Avenue S.W.
(403) 290-6000
FAX (403) [illegible]
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March 21, 1990

Via Fax: 613-563-7800

Fraser & Beattie
180 Elgin Street, Suite 1200
Ottawa, Ontario
K2P 2K7

Attention: Nick Schultz

RE: NOVA Fuel Gas Charges

Further to your telephone conversation this morning with John Latyn, NOVA recovers is fuel gas usage from all shippers in kind. Fuel usage is allocated equally based on a shipper's receipt volumes in a month.

The current fuel usage ratio is approximately 0.75% (three-quarters of one percent).

If you require any further information, please contact me at 403-290-7492.

Yours truly,
NOVA Corporation of Alberta

Robin D. Paton
Supervisor Rates & Regulatory

RDP/rp

TRANSCANADA PIPELINES LIMITED
LIST OF TOLLS

Service	Monthly Demand Toll ($\$/10^3 m^3/mo$)	Commodity Toll ($\$/10^3 m^3$)
from Empress to Niagara Falls		
FS	791.32	2.782
IS-1		35.302
IS-2		31.689
from Empress to Cornwall		
FS	808.35	2.839
IS-1		36.059
IS-2		32.368
from Empress to Sabrevois		
FS	843.92	2.971
IS-1		37.653
IS-2		33.799
from Empress to Philipsburg		
FS	851.77	3.000
IS-1		38.004
IS-2		34.115
from Herbert to Emerson		
FS	239.00	0.721
IS-1		10.543
IS-2		9.452
from Success to Niagara Falls		
FS	727.70	2.572
IS-1		32.477
IS-2		29.155
from St. Clair to Niagara Falls		
FS	111.41	0.251
IS-1		4.829
IS-2		4.321

ATTACHMENT 3

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

CHAIRMAN

April 9, 1990

APR 11 1990

Honorable Philip R. Sharp
Chairman
Subcommittee on Energy and Power
Committee on Energy and Commerce
House of Representatives
Washington, D.C. 20515

Dear Chairman Sharp:

Thank you for your letter of February 22, 1990, concerning proposed natural gas pipeline additions to serve the Northeast U.S. during the next ten years. You also requested an estimate of potential increased LNG imports and other potential gas pipeline capacity additions expected over the same period. Finally, you request an estimate of the extent to which new pipeline capacity or LNG imports may supplant oil or coal as a fuel for generating electricity in the Northeast.

A summary of pending proposed additions in service to the Northeast which identifies the project, sponsor(s), projected volumes on a peak and annual basis and whether the sources of supply include imported gas is appended. The volumes are based on the first full calendar year of service. The listed projects were generally filed under the conventional Natural Gas Act (NGA) Section 7(c) procedures and NGA Section 3 import/export authority. One proposal (Indiana Ohio) was filed under the NGA section 7(c) optional procedure. However, that facility is currently being constructed pursuant to section 311 of the Natural Gas Policy Act (NGPA). We are not aware of any other proposal to serve the Northeast through facilities to be built under Section 311. We are also aware of no potential capacity additions to serve the Northeast not reflected in the appendix.

Most of the volumes represented on the appendix are attributable to projects specifically found discrete, or non-competing, in the Commission's Northeast U.S. "open-season" proceeding. None of the listed projects has been found to be in competition with other projects. Therefore, there is no known "double-counting" of volumes represented in the appendix, with two possible exceptions. The volumes in the Indiana Ohio filing, may compete in part with the ANR (Lebanon Extension) filing. However, these parties appear to have reached a settlement which may eliminate any potential duplicate capacity. In any event, since the risk of the Indiana Ohio facilities is on the shareholders of applicant under the optional certificate procedure, ratepayers will not be harmed if the project sponsors' projections are not fully realized. Also, the National Fuel application proposes to replace Empire State's border crossing facilities and part of its downstream line.

The Commission has previously found to be discrete and approved 18 projects that would provide new service to the Northeast. The gas underlying these projects would be 66% domestic and 34% Canadian. The source of gas for the seven pending Northeast discrete projects (excluding the Champlain project, currently held in abeyance at the request of the project sponsors) and the Indiana Ohio project is estimated to be 45.7% domestic and 54.3% Canadian. Combining the previously authorized projects with the seven pending discrete projects and Indiana Ohio would result in 53.5% domestic and 46.5% Canadian production underlying these projects. In addition, other proposed projects in the Northeast which have not been found discrete include the Steuben Gas project, Falcon Seaboard, Niagara Mohawk and Empire State projects. The Steuben Gas project would involve domestic gas. The Falcon Seaboard and Niagara Mohawk projects would involve Canadian gas. As structured, the Empire State project could involve either domestic or Canadian production, or a combination.

You further request that we provide reasonable projections for increased LNG imports into the Northeast through the year 2000 and estimate what other pipeline applications may be filed in this time period. The Energy Information Administration (EIA) of the Department of Energy is responsible for projecting long term energy needs. However, the Commission often receives projections and studies in support of proposed projects. We will attempt to answer your inquiry using these references.

There are two possible direct sources of LNG supply to the Northeast. Distrigas of Massachusetts Corporation (DOMAC) is currently operating an LNG facility at Everett, Massachusetts, with a maximum sendout capacity of 285,000 Mcf per day or 104 Bcf per year. The facility was recently reactivated and currently has authority to send out 51 Bcf per year. From July through December 1989, the sendout was 20.9 Bcf. Columbia LNG Corporation (Columbia) and Shell Oil Company propose to reactivate the moth-balled LNG facility at Cove Point, Maryland. This facility has a maximum sendout of 1 Bcf per day or 365 Bcf per year. Columbia Gas System Inc. has stated that first deliveries of LNG to the terminal could occur as early as the winter of 1991-92. Therefore, the maximum potential LNG supply to the Northeast through the year 2000, including the DOMAC and Columbia facilities, is 469 Bcf per year. However, complicated operating logistics of LNG facilities, potential pipeline capacity constraints and transportation costs from Cove Point to the Northeast, and the market price of gas and competing fuels will affect the extent to which these facilities are used. We are aware of no proposals to construct new LNG facilities in or near the Northeast. If such a facility were proposed, it would be several years before it became operational.

There are two other LNG facilities in the United States. Southern Energy Company owns a facility at Elba Island, Georgia, with a sendout capacity of 118 Bcf per year. This facility is currently inactive. Trunkline LNG Company operates a facility at Lake Charles, Louisiana, with a sendout capacity of 255 Bcf per year, which was recently reactivated. Again, pipeline transportation costs, operational constraints on pipelines and LNG terminals, as well as costs and availability of alternative gas and other fuels will all affect these facilities' ability to impact gas supplies in the Northeast.

The American Gas Association (AGA) has developed projected totals through the year 2000 for all four facilities assuming various pricing scenarios (Gas Energy Review, AGA, January 1990, volume 18 No. 1, p. 8). AGA projects LNG import potentials ranging from 350 Bcf to 600 Bcf to 800 Bcf in the year 2000 assuming oil price ranges of $18 to $22, $20 to $27 and $30 to $38 per barrel, respectively. The LNG facilities serving the Northeast account for 56 percent of this total potential LNG. Based on the foregoing information, the potential range of LNG deliveries to the Northeast in the year 2000 vary from 200 Bcf to 340 Bcf to 450 Bcf.

With regard to potential applications to increase pipeline capacity additional to those listed in the appendix, the Commission has no information. National Fuel recently filed an application in Docket No. CP90-920-000. This application proposes to replace Empire State's border crossing facilities and part of its downstream line. National Fuel would also serve three cogeneration facilities with 39 MMcf of Canadian Gas on a peak day basis. Also, CNG filed an application in Docket No. CP89-493-000 to construct facilities to serve 3 other cogeneration facilities in New York at a total peak day capacity of 26 MMcf in domestic volumes.

Finally, you request an estimate of the extent to which proposed or estimated new deliveries of natural gas over the next 11 years may supplant oil or coal as a fuel for generating electricity in the Northeast. Such an estimate would be an uncertain endeavor. The most that can be said at this point is that displacement of oil or coal at existing generating stations will probably be minor and that much of the projected growth in generating capacity will be fueled with gas.

Only a few of the intervenors in the Northeast cases cited in the appendix propose to replace oil with gas for electricity generation. For example, the New England Power Pool (NEPOOL) stated in the Northeast open season proceeding in 1988 that only 30 of approximately 300 electric generating units now using oil as their primary fuel are potential candidates for repowering using gas as the primary or alternate fuel. Repowering could increase the generating capability of these plants from 2000 MW to 7000 MW. NEPOOL members currently have 24,000 MW on line. New England Power (NEP), a participant in NEPOOL, claims a need for up to 95 MMcf/day to add natural gas burning capability to an existing plant in order to comply with Massachusetts acid rain legislation. No. 6 residual fuel oil will be the backup alternate fuel. NEP also has plans to repower a plant, using combined cycle technology, using up to 95 MMcf/day of gas as the primary fuel. No. 2 fuel oil will be the backup fuel. Even these few examples of oil replacement do not represent complete displacement of oil by gas and involve a repowering to increase the electric generation capability. We are also not aware of any cases of coal displacement. Coal represents approximately 12 percent of New England's electric generating capacity.

Projections of increased demand for gas to generate electricity in the Northeast rest on the Northeast's growing demand for electricity and on environmental concerns. For example, NEPOOL stated in a pleading in one of the Northeast dockets that: "Of the generating capacity additions that are proposed to be constructed and placed in operation by the NEPOOL participants in the period between January 1, 1989, and January 1, 2005, nearly 1300 MW is planned to use gas as a primary fuel. This is somewhat more than 70 percent of the total MW of capacity currently scheduled to be placed in operation by the NEPOOL participants, other than the Seabrook unit." AGA, in its TERA Base Case Analysis (89-1) of future energy needs, also projects a major role for gas in serving the growth in Northeast electric generation. For the period 1988 to 2010, AGA predicts that Northeast growth in electric generation will be 2.52 Quads or 59.8 percent. Of this total, 1.33 Quads or 53 percent would be served by natural gas.

The Energy Information Administration (EIA) in its study, "Regional Projections of End-Use Energy Consumption and Prices through 2000" (DOE/SR/EAFD/89-01), estimates the oil displacement demand for gas at N.E. power plants will increase from .31 Quads in 1988 to .36 Quads in 2000, a 14 percent increase. The gas share of total energy in power plant demand is projected to remain at seven percent during this period. The North American Electric Reliability Council in its "1989 Electricity Supply and Demand For 1989-1998", projects that regional gas requirements for electricity production in the Northeast Power Coordinating Council, which includes NEPOOL and New York, will increase from 168.7 Bcf in 1988 to 177.0 Bcf in 1998, a five percent increase.

In conclusion, the projected growth of gas demand for electric generation in the Northeast varies considerably among forecasters. The portion of total energy used to produce electricity that will be provided by natural gas is also uncertain. However, there appears to be a general consensus that there will be some increase in the market share of gas.

It should be noted that forecasts cited above do not account for the potential effects of clean air legislation which is currently being considered by the Congress. Until this legislation is finalized, predictions of its effect on fuel choices would be pure speculation.

If I can be of further assistance in this or any other Commission matter, please let me know.

Yours truly,

Martin L. Allday

Martin L. Allday

Enclosure

APPENDIX

PENDING PROPOSED ADDITIONS IN SERVICE

Project	Period	MMcf Daily	MMcf Annual at 100% Load Factor
Niagara Import Point, Transco National, Tennessee, Algonquin Penn York, CNG, TETCO Great Lakes § 7(c)	1991-2000	493	179,945
Public Service Tennessee § 7(c)	1991-2000	25	9,125
APEC IV CNG, TETCO § 7(c)	1991-2000	99	9,900
CRP/LNG TETCO § 7(c)	1991-2000	102	7,140
TETCO CDS § 7(c) TETCO	1991-2000	148	54,020
Iroquois/Tennessee § 7(c)	1992-2000 1993-2000	546 100	199,290 36,500
ANR ANR, Columbia CNG, Algonquin Transco, Texas Gas § 7(c)	1992-2000	503	183,595
Steuben Gas Storage Steuben, CNG, Transco § 7(c)	1992-2000	59	6,200
Falcon Seaboard § 3	1992-2000	54	19,710
Niagara Mohawk § 3	1992-2000	51	18,615
Empire State § 3	1992-2000	150	54,750
Indiana Ohio Optional	1991-2000	200	73,000
CNG § 7(c)	1991-2000	26	9,490
National Fuel § 7(c)	1991-2000	39	14,235

PEAK DAY AND ANNUAL VOLUMES INTO NORTHEAST EXCLUDING CHAMPLAIN (Bcf)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Peak	1.13	2.49	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59
Annual	284	840	876	876	876	876	876	876	876	876

2 of 2

AGA American Gas Association

1515 Wilson Boulevard, Arlington, Va. 22209
Telephone (703) 841-8612

Michael Baly III
Executive Vice President and
Chief Operating Officer

April 30, 1990

Honorable J. Bennett Johnston
Chairman
Committee on Energy and
Natural Resources
United States Senate
Washington, D.C. 20510

Dear Chairman Johnston:

The American Gas Association (A.G.A.) is a trade association comprised of some 250 natural gas distribution and transmission companies serving 166 million consumers throughout the United States.

We are aware that your Committee has scheduled oversight hearings on May 3, 1990 to consider matters relating to pending FERC and DOE matters in the Iroquois Gas Transmission System, L.P. and Brooklyn Union Gas Company, et.al. We respectfully request that this letter be made part of the record of those hearings.

The need for additional long-term gas supplies and new pipeline capacity to serve the growing requirements of the Northeast market is well documented and, in our view, not subject to genuine dispute. In numerous hearings and comments before Congress and the Federal Energy Regulatory Commission, A.G.A. has stressed the urgent and immediate need for more natural gas delivery capacity in the Northeast.

Data from both A.G.A. and the Energy Information Administration (E.I.A.) show that the Northeast has had a 28 percent increase in gas demand over the last 10 years (1978 - 1988) -- a period when many other areas of the U.S. showed decreased demand. One part of the region, New England, had an extraordinary 33% increase in gas demand since 1978.

Demand is increasing in all market sectors -- residential, commercial, industrial and electric generation. While some of this demand increase is due to fuel switching, i.e. temporary or permanent conversions from fuel oil to natural gas, some of the increase is also due to the Northeast's strong economy and the construction of new homes and offices. That same strong economy and new construction boom also is increasing electricity demand in the Northeast. Because of environmental and siting constraints, natural gas-fired combined cycle turbines, cogeneration units and select use applications are crucial to meeting the demand for electricity in the region. Indeed, the need for new energy sources in the Northeast is so crucial that, unless new pipeline capacity is constructed, 345 Bcf of potential gas demand will shift to alternative fossil fuels. Such fuel switching has measurable adverse environmental and energy security consequences.

A.G.A. has testified extensively on the need for new pipeline capacity in Congress and in filings before the Commission. The tenor of our comments has been that the regulatory process should be flexible enough to bring needed new pipeline capacity on-line expeditiously. As we understand it, your hearing is not intended to focus on the need for gas in any specific geographic region but on the regulatory process itself. With regard to that process at FERC, A.G.A. has urged that the process be expeditious, since we believe that prompt regulatory action is essential to achieving the bright promise offered by increased availability of natural gas. On September 28, 1988, A.G.A. testified before the House Energy and Commerce Subcommittee on Energy and Power. Although the hearing topic was Northeast pipeline capacity, we pointed out that FERC's certificate process needed to be expedited through additional regulatory resources:

> While increased regulatory attention to the Northeast projects is urgently needed, we recognize that this will require that more regulatory resources be devoted to the entire area of pipeline capacity construction projects. As important as increasing pipeline capacity to the Northeast is, both to the region and to the nation, there are also other critical projects that await regulatory review and approval.

In 1988, FERC was confronted with dozens of certificate applications for new projects to serve the Northeast. In response to this intense regulatory activity, the Commission instituted an "open season" for applications to serve the Northeast. By January, 1989, 72 proposals had been received, 35 of which were filed during the open season that ended January 15, 1989, while the remainder were filed prior to the "open season".

To expedite consideration of these many projects, FERC consolidated applications into smaller groups and categorized projects as being either discrete (i.e., proposing separate and distinct service) or competing (i.e., proposing similar or identical gas service). Twenty projects, including Iroquois, were initially slated for the latter designation, which would have subjected them to lengthy comparative reviews. FERC then directed its Chief Administrative Law Judge to convene settlement conferences wherein a number of project sponsors altered their proposals to avoid comparative hearings.

One purpose of FERC's "open season" proceeding was to solicit the input of the public and private sectors, including all segments of the gas industry, on the most appropriate means of serving the requirements of the Northeast gas market. This regulatory process led to approval of a number of projects intended to bring additional domestic gas supplies to the Northeast. (We are pleased to note that those projects are moving forward and some are now in service.) On the other hand, the "open season" settlements also included major pipeline projects, like Iroquois, which take advantage of the long-term energy reserves of Canada. In our view, assuring access of the Northeast market to Canadian natural gas reserves is vital to the region's energy security, which is currently reliant on imported oil to serve much of its growing energy needs.

Having completed the eighteen month "open season" process, the task that lay before the federal regulatory agencies was to complete the environmental reviews and certificate proceedings in an orderly and expeditious manner. In the months since conclusion of the "open season" settlement process, the FERC and DOE have worked diligently to that end. With regard to the Iroquois pipeline project and related Brooklyn Union, et. al. gas supply project, the stated objective has been to conclude all regulatory proceedings by the end of the 1990 summer, so that these gas supplies and new pipeline capacity will be available to the market by November 1, 1991.

A.G.A. supports this objective and opposes any legislative change to the Natural Gas Act that would subject these projects to trial-type evidentiary hearings. FERC has already considered such issues as the need for additional gas supplies, and differentials between U.S. and Canadian pipeline rate regulation. These are issues of policy that have been decided by FERC and DOE on the record presently before them. The only thing that would result from trial-type hearings is delay, which would be both unnecessary and harmful.

A.G.A. is concerned about the depressed conditions that affect our independent domestic gas producers. Delaying the Iroquois and Brooklyn Union, et. al. proceedings will not resolve the independent domestic producer's difficulties. Indeed, we believe the opposite to be true. The pipeline capacity bottleneck in the Northeast, which was one of the prime reasons for the many construction applications on file at FERC, limited opportunities for transporting domestic gas supplies to that market. The Iroquois pipeline and the related Tennessee pipeline and Algonquin Gas Transmission capacity expansions will effectively eliminate that bottleneck and create significant opportunities for delivery of domestic supplies to the Northeast, both directly and by displacement. These opportunities should prove particularly valuable to independent producers, whose reserve base does not permit them to make the kind of long-term contractual commitments necessary to finance major new pipeline capacity. With the long-term contractual arrangements available from Canadian suppliers as the support for the Iroquois, Tennessee and Algonquin capacity, the independent producers can utilize that capacity to implement shorter term contractual arrangements.

We appreciate this opportunity to contribute to the record of the Committee's May 3 oversight hearings.

Respectfully,

Mike Baly III

Michael Baly III

INGAA

JERALD V. HALVORSEN
PRESIDENT

May 2, 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
364 Senate Dirksen Office Building
Washington, D. C. 20510

Dear Mr. Chairman:

The Interstate Natural Gas Association of America (INGAA) is a trade association representing all of the major interstate natural gas transmission companies operating in the United States and inter-provincial pipelines operating in Canada. INGAA's members account for over 90 percent of all natural gas transported and sold in interstate commerce.

We are writing to provide you our views for the oversight hearing scheduled for May 3, 1990, to consider matters relating to pending Federal Energy Regulatory Commission (FERC) and Department of Energy (DOE) decisions in the *Iroquois Gas Transmission System L.P.* and *Brooklyn Union Gas Company, et al.* proceedings. We respectfully request this letter be made part of the record of those hearings.

The pending Iroquois decision follows over four years of the most thorough and intense federal, state and local regulatory and environmental review ever accomplished for a gas pipeline project. That review demonstrates the critical need for additional natural gas supplies and incremental pipeline capacity in the U. S. Northeast in the near future, and strongly supports approval of the Iroquois project as one necessary part of the overall solution to those critical supply and capacity needs.

While domestic producers are now providing the bulk of U.S. Northeast gas requirements, Iroquois' proposed new pipeline capacity will serve both practical and competitive needs in the Northeast. While

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
555 13TH STREET, N.W., #300 W • WASHINGTON, D.C. 20004 • 202/626-3200

Iroquois is dependent on shippers who have made long-term supply arrangements with Canadian producers, that kind of assured volume is essential for financing major new pipeline construction. Many domestic producers are unwilling at this time to provide such supply certainty. Nonetheless, once the Iroquois capacity is constructed all producers who wish to serve the Northeast will have new opportunities. Although Canadian gas imports to the Northeast and other regions of the United States are small in comparison to domestic supplies, the availability of Canadian gas provides U. S. consumers with the benefits flowing from increased competition and a diversity of market choices.

Notwithstanding these indisputable record findings, fuel oil dealers and independent gas producers are now advocating trial-type evidentiary hearings to challenge once again the need for the Iroquois pipeline and to oppose Canadian gas imports on the basis of an alleged anticompetitive rate structure. These allegations have been found to be without merit in every previous agency and court proceeding that has addressed them.

U.S. consumers have found Canadian gas supplies to be competitive, reliable and available on a long-term basis. Such experience is consistent with the goals of the U. S.-Canadian Free Trade Agreement. Further, a study recently completed by INGAA (copy enclosed) found no significant evidence of economic or tax advantages to Canadian producers over U.S. producers.

We appreciate this opportunity to contribute to the record of the Committee's May 3 oversight hearings.

Respectfully,

Jerald V. Halvorsen
President

RLB/jda

Enclosure

INGAA

Report No. 90-1R

March 1990

Rate and Policy Analysis Department

Background Report

—

COMPARATIVE ADVANTAGE OF INVESTMENT IN CANADIAN VERSUS U.S. NATURAL GAS PRODUCTION: Update on Tax and Royalty Incentives

Executive Summary

During the mid-1980s, Canadian federal and provincial governments implemented various tax and royalty incentives to promote oil and gas exploration and development during a period of low commodity prices. Those incentives, coupled with the differences in U.S. and Canadian tax treatment of production-related expenses, generated considerable discussion about the comparative profitability of investment in the exploration and development of natural gas in Canada relative to the U.S. A review of current differences in U.S. and Canadian tax and royalty structures leads to several observations:

- Most of Canada's special incentives have either expired or been reduced.
- Many of the Canadian special incentives imposed dollar limits per producer that focused the benefits of the programs primarily on smaller producers; the impact on marginal investment decisions by large producers has been limited.
- Though diminished over the last two years, the profit potential of exploration wells in Canada would still appear to be marginally higher than comparable wells in the U.S., based solely on the difference in the tax treatment of expenses.

While the differences in tax and royalty structures clearly have an impact on the relative profitability of investment in natural gas production between the two countries, a number of other factors are likely to be equally important. Different geological conditions, regulations, commodity prices, interest rates, exchange rates, and transportation costs to consuming markets could well wash out the impact of different tax and royalty incentives. With the phaseout and reduction in most of the incentive programs, any profit advantage for investment in Canadian over U.S. natural gas production due to tax and royalty incentives has been diminished. Due to the structure of the remaining incentives, Canadian producers would experience even further erosion of the benefits should gas markets tighten and prices rise.

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PREFACE

A Background Report is an INGAA document which presents the results of research into a particular subject of interest to the interstate natural gas industry. Background Reports are not aimed at in-depth discussion of policy issues, but rather are initial analyses which reach tentative conclusions.

This particular report was prepared to provide information updating the issue of comparative advantage in natural gas production in Canada versus the U.S. due to differences in the tax and royalty structures between the two countries. The report has been revised to reflect the early elimination of the Canadian Exploration Incentives Program (CEIP), announced as part of a federal budget reduction on February 21, 1990. Any questions or comments should be directed to Shirley Neff.

INTRODUCTION

During the mid-1980s, the Canadian federal and provincial governments implemented various special incentive programs to encourage exploration and development during a period of low commodity prices. Several 1988 U.S. studies prompted by debate over ratification of the U.S.-Canada Free Trade Agreement found that the cumulative effect of the various tax and royalty incentives, coupled with the inherent differences in the tax and royalty structures between the two countries, made investment in oil and natural gas production in Canada somewhat more attractive than in the U.S. Because the debate continues over the comparative advantage that Canadian oil and gas producers purportedly hold over U.S. producers due to tax and royalty incentives, INGAA has undertaken this review of the changed environment.

Two studies in particular, one by the U.S. Department of Energy (DOE) and the other by the American Gas Association (AGA), summarized the major distinctions between the U.S. and Canadian tax and royalty structures which may arguably have an impact on relative investment decisions.[1] The studies assumed for comparative purposes that all Canadian production comes from the province of Alberta.[2] Based on the differences in tax and royalty treatment of exploration and development well drilling, both the DOE and AGA studies concluded that smaller, independent Canadian producers had a potential profit advantage over U.S. producers. The studies' conclusions were different with respect to production by larger Canadian producers for whom many of the incentives were so diluted as to be insignificant from the standpoint of marginal investment decisions. A major reason for this conclusion was that a number of the incentive programs had dollar limits intended to focus the benefits on small, independent producers. The DOE study concluded that even though the benefits from the incentives were significantly lower for larger producers, combined with provisions of the tax code, investment in Canadian production would still generate a higher return than comparable investment in the U.S. The AGA study, by contrast, concluded that the absence of the incentives available to smaller Canadian producers gave U.S. producers in general a comparative advantage over larger Canadian producers. While this report highlights the differences in tax and royalty structures described in those studies, it does not attempt to redo a quantitative assessment; instead we cite without comment the results of prior studies by others, and note any changes which have occurred in the intervening period.

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[1] Both studies noted essentially the same tax and royalty differences between the U.S. and Canada, then used different financial analyses to develop conclusions regarding the significance of these differences. The DOE analysis entailed calculating discounted rates of return for typical oil and gas wells in each country. *U.S. and Canadian Tax and Fiscal Treatment of Oil and Gas Production*, Working Paper, U.S. Department of Energy, Office of Policy, Planning, and Analysis, Division of Oil, Economic and Energy Tax Policy, Revised May 9, 1988. The AGA study compared the net present value of the earnings from a set of comparable exploration and development wells in the U.S. and Canada, assuming no difference in geological circumstances or drilling costs. "U.S.-Canadian Drilling Comparisons," *Energy Analysis*, AGA Planning and Analysis Group, May 1988.

[2] In 1988 over 85 percent of all Canadian natural gas production was from Alberta.

Comparison of the Royalty and Tax Structures in the U.S. and Canada

The U.S. and Canadian tax and royalty structures are sufficiently different to make a direct comparison difficult. Table 1, discussed in the following paragraphs, contains a subjective summary of the relative importance of the different tax and royalty items, including the special incentives, on industry investment in new production.

Royalties

Although both are based on a percent of wellhead revenues, royalties in the U.S. and Canada differ significantly. U.S. royalty rates, which vary among states and producing areas, generally range from 12.5 to 25 percent of gross revenues and currently average about 18.75 percent for developed fields.[3] Royalty rates in Canada are established by the provincial authorities. Alberta royalty rates are progressive, based upon wellhead price and the level of production, and impose greater administrative burdens on Canadian producers. Royalties for new gas at current wellhead prices are approximately 25 percent, with a minimum payment level to prevent provincial revenue erosion as a result of producers selling at low spot prices. Before the royalty is calculated Canadian producers are allowed to deduct from revenues a "gas cost allowance" representing the cost of producing and compressing the province's share of production. This deduction effectively lowers the royalty rate, but not lower than U.S. royalty rates. Canadian royalties are paid largely to the provinces, which control most of the land on which oil and gas is produced. The provincial governments use royalty policies as a fiscal tool. For example, royalty holidays, a forgiveness of the royalties due the province for a given period of time, were implemented in the mid-1980s to encourage new production.

---

[3] The figures on royalty rates are from the 1988 DOE study, and are still valid.

Table 1
U.S. and Canada Relative Advantages of Tax and Fiscal Treatment of Natural Gas Exploration and Development

	CANADA		U.S.	
	Small Producers	Large Producers	Small Producers	Large Producers
OVERALL TAX & ROYALTY STRUCTURE				
Royalties			B	B
Tax Rates	C	C		
Exploration Wells	A	A		
Development Wells			B	C
SPECIAL INCENTIVES (expiration or review dates)				
Deep Well Royalty Holiday	C	C		
Royalty Tax Credit* (12/94, reduced 1/90)	B			
EXPIRED CANADIAN INCENTIVES (In effect 1986-89)				
CEDIP - E&D Drilling Credit (exp. 4/89)	A			
Exploratory Well Royalty Holiday* (exp. 12/89)	A	A		
CEIP Drilling Credit* (exp. 2/90)	A			

* Incentives incorporated in DOE and AGA studies.

Scale: A to C are subjective rankings by the author, with A indicating the most significant relative advantage. The rankings are based roughly on the impact of a given item on the industry as a whole. For example, the Canadian exploratory well royalty holiday, although worth only C$2 million compared to C$3.6 million per well for the deep well royalty holiday, is ranked higher since it could potentially be applicable to more wells.

Tax Structures

Depending upon location, natural gas production in the U.S. is subject to various forms of taxation – federal, state and local income taxes, as well as revenue-based severance or production taxes. Canadian production is subject primarily to federal and provincial income taxation. Taxes and royalties in the U.S. are deductible for state and federal tax purposes, whereas Canadian royalties, as well as provincial income taxes, are not deductible for federal tax purposes. However, the Canadian federal government allows a "resource allowance" deduction of 25 percent of net income, which may or may not offset the non-deductibility of royalties. Alberta has a special royalty tax credit described below. The U.S. and Canada both implemented significant tax reforms in the late 1980s. The post-reform tax rates are as follows:[4]

Table 2
U.S. and Canadian Tax Rates

	U.S. (%)	Canada (%)
Federal Income	34	28.84
Provincial/State and Local Income	4-7	15
Severance*	6-10.9	None

* Severance, or production, taxes are calculated on gross revenues, not net income.

In addition to the tax rates, significant differences in the general tax treatment of exploration and development costs exist between the U.S. and Canada.

Exploration. The Canadian tax code allows more favorable treatment of exploration expenses than do the U.S. rules. Canadian producers may write off all geological and geophysical expenses in the first year, while U.S. producers must amortize these expenses over the life of the property. The longer amortization period in the U.S. is especially significant in frontier areas where these expenses tend to be high. Intangible drilling costs (IDCs) may be fully expensed in the first year for all Canadian exploratory wells. All U.S. producers may expense dry hole costs the first year. U.S. independent producers may expense 100 percent of intangible exploratory drilling costs, subject to the Alternative Minimum Tax (AMT);[5] whereas integrated producers may only expense 70 percent in the first year, recovering the remainder over the next five years. Canadian producers may also pool expenses to carryover to future years. For growing Canadian producers engaged in both exploration and development, this provision enables a producer to carry over expenses indefinitely to reduce taxable income.

Development. U.S. producers appear to have at least a slight tax advantage in drilling development wells. Independent U.S. producers may expense 100 percent of development well intangible drilling costs, subject to the Alternative Minimum Tax; and, as with exploratory wells, integrated producers may expense 70 percent the first year. Canadian producers, however, must use a 30 percent declining balance method for development well expenses, a notably longer recovery period than in the U.S.

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[4] Summary of tax rates is from the 1988 AGA study.

[5] A report by Energy and Environmental Analysis, Inc., prepared for the Gas Research Institute, estimated that less than half of all U.S. exploration and development expenditures are made by independents eligible to fully expense intangibles. EEA, *Representation of the Tax Reform Act of 1986 in the Hydro-carbon Supply Model*, 1987.

Independent U.S. producers are also eligible for a 15 percent depletion allowance against oil and gas production under certain circumstances.[6] In addition, U.S. producers also receive slightly more favorable depreciation of drilling and lease and well equipment. (These last two items also apply to exploratory wells, but given the Canadian treatment of other expenses are comparatively less significant.)

Canadian Incentive Programs

At the time of the 1988 studies, Alberta producers were eligible for various royalty holidays and tax incentives to offset exploration and development costs. The programs in place at that time included:

- a one-year royalty holiday for exploratory gas wells, worth up to C$2 million per well;
- a royalty holiday for deep gas wells, worth up to C$3.6 million per well based upon the well depth and incremental drilling cost;
- a provincial tax credit, the Alberta Royalty Tax Credit (ARTC), for 75 percent of oil and gas royalties paid to the province to a cap of C$3 million per producer;
- a drilling incentive offered by the federal government, the Canadian Exploration Incentive Program (CEIP), a cash incentive of 30 percent of drilling expenses up to C$3 million for companies using flow-through share financing.

The Canadian Exploration and Development Incentive Program (CEDIP), another federal incentive noted, but not directly included in the studies' quantitative analyses due to its impending expiration, provided cash refunds for certain exploratory and development well expenses from June 1987 through the end of 1989. Initially the refund was capped at C$3.3 million per producer, then reduced to C$1.67 million in 1988.[7] The incentives received under the federal CEIP and CEDIP programs reduce the expenditures deductible for tax purposes.

Several programs have since expired or been reduced. The exploratory well royalty holiday expired in December 1989. The program was eliminated because an unreleased Alberta DOE internal study found that the exploration well holiday was not cost effective. The CEDIP, the federal credit available for both exploration and development, was eliminated in April 1989, eight months ahead of schedule. The CEIP, originally scheduled to be reviewed in October 1990, was terminated in February 1990 as part of a federal budget reduction. With the elimination of the CEIP, no special federal incentives for gas production remain. The Alberta Royalty Tax Credit, previously worth C$3 million per producer, has been reduced. Effective January 1990, the program was tightened by restricting the eligibility of affiliate companies.[8] At the same time, the credit was reformulated and pegged to the market price of oil: the cap is now C$2.1 million at oil prices of US$14.50 per barrel. At current prices the credit is worth only about C$1.8 million per producer. A number of oil well royalty holidays indirectly affecting associated gas production were also introduced and phased out during the period from 1986-89.

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[6] The same EEA report for GRI estimated that roughly 7 percent of all domestic exploration and development expenditures are made by independent producers who qualify for percentage depletion on new wells.

[7] The CEDIP was essentially replaced by the CEIP. During the overlapping period, exploration expenses could not qualify under both programs.

Impact of Tax and Royalty Incentives on Investment in Natural Gas Production

As pointed out in a recent study by Amoco Corp.,[9] there would appear to be a correlation between the increase and subsequent decline in oil and gas drilling activity in Canada as the various incentives phased in and out between 1986 and 1989. While the differences in tax and royalty structures clearly have an impact on the relative profitability of investment in oil and gas production between the two countries, a number of other factors are likely to be equally important. Different geological conditions, regulations, commodity prices, exchange rates, interest rates, and transportation costs to consuming markets could well wash out the impact of different tax and royalty incentives.

Assessing the impact on Canadian drilling activity directly attributable to the tax and royalty incentives would require a detailed review of a number of economic factors and statistics relative to the gas industry over that same period. For example, Canadian gas well completions actually rose from 1986 through 1988 before leveling off in 1989, in spite of the reductions in available incentives.[10] U.S. demand for imports of Canadian gas increased significantly from just over 0.9 Tcf in 1985 to 1.3 Tcf in 1989. At the same time, the Canadian dollar appreciated more than 15 percent against the U.S. dollar between 1986 and 1989. Under export pricing arrangements in U.S. dollars this appreciation would have decreased per unit net revenues to Canadian producers relative to U.S. producers. Clearly, a number of dynamic factors were at work over the period which individually exerted different directional forces on investment in Canadian natural gas production including, but not limited to, the various tax and royalty incentives.

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[8] A "double dip" provision, exempting certain associated companies from the rule requiring them to share the ARTC, was eliminated effective with the tax year ending in 1991.

[9] "Fiscal Incentives and World Petroleum Exploration Since 1986," paper filed by Amoco Corporation with the Department of Energy, January 11, 1990, in response to a request from national energy strategy hearings in 1989.

[10] Based on data from the Canadian Petroleum Association, including preliminary data for 1989.

CONCLUSION

With the phase out of all federal and most of the provincial incentive programs, any profit advantage for investment in Canadian over U.S. natural gas production due strictly to tax and royalty incentives has been diminished. Due to the structure of the remaining Alberta Royalty Tax Credit, Canadian producers would experience even further erosion of the benefits should gas markets tighten and prices rise.

New York State Energy Office
2 Empire State Plaza
Albany, New York 12223

New York State Dept. of
Public Service Commission
3 Empire State Plaza
Albany, New York 12223

May 1, 1990

Honorable J. Bennett Johnston, Chairman
Senate Committee on Energy and Natural Resources
SD-364
Washington, DC 20510

Dear Chairman Johnston:

The New York State Energy Office (SEO) and the New York State Department of Public Service welcomes the opportunity presented by your May 3, 1990, hearing on Canadian gas import projects to let you know how important increased natural gas supply and expanded pipeline capacity is to our state, particularly via the Iroquois project.

There is a strong and growing market for natural gas in New York and the entire Northeast. This market is big enough to absorb all the increased gas deliveries approved and pending in the open season, and much more. To facilitate the increased use of gas throughout the Northeast, we must maintain the momentum towards completion of pending projects and complete them as soon as possible.

The most recent New York State Energy Plan (September, 1989) states that New York State should act to increase the cost effective and efficient use of natural gas by at least 50 percent by 2008. A major finding of the State Energy Plan is that the existing interstate natural gas pipeline infrastructure is inadequate to meet projected requirements.

The needs of New York's core market customers are expected to grow, especially during peak periods. Further, the future use of gas to generate electricity is projected to be nearly as large as that of the core market, given the siting and lower air emissions advantages of gas fired generation.

However, even if all the capacity for New York proposed under both the open season projects and various intrastate pipelines (e.g. the Empire State Pipeline) are approved and constructed, these projected demands can not be met.

We have been satisfied with the progress made in the open season thus far. We applaud FERC's efforts to structure a streamlined process and act as expeditiously as possible. The open season provided a market-driven mechanism for natural gas consumers to make gas supply arrangements with either domestic or Canadian suppliers. This resulted in an equal mix of increased domestic and Canadian volumes planned for the Northeast.

The principal domestic supply element of the open season, the ANR project, recently was amended to provide expanded domestic volumes to the Northeast (CP 89-637-001, et al). The ANR project would deliver gas to the Northeast via ANR, Texas Gas, Transco, CNG, Columbia, and Algonquin. New York would receive substantial volumes for cogenerators under this project. ANR is also an important link for delivering domestic gas in New York via the proposed Empire State Pipeline.

Substantially all of the open season projects that depend on domestic supplies have continued to move through the regulatory process toward certification. However, at this late stage of review, the Canadian import projects face challenges from domestic producers. We are concerned by the recent delay in review of the Niagara Import Point project. This delay resulted from attempts by domestic producers to introduce certain policy issues into the proceeding[1]. Now the Iroquois-Tennessee project faces the same challenges.

We feel that additional delays in the regulatory process, especially for the Iroquois project, could have serious long term negative effects on the energy needs of the Northeast region.

Since 1986 our need for additional pipeline capacity has increased to the point where restrictions on new gas attachments might be needed soon in certain areas of New York. Such restrictions would confirm the views of gas industry's skeptics who claim that gas is not reliable fuel source.

Delays also could jeopardize some of the underlying agreements that were made in the open season settlement process and potential new markets would be lost during the time it takes a new project to emerge and develop. The Iroquois project has been under development for five years and New York has been relying on it and the Niagara Import Point Project to meet urgent market needs. Alternatives are simply not available on a timely basis.

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[1] Domestic producers claim that Canadian producers have unfair competitive advantages, primarily related to different rate-making procedures. These issues were discussed in DOE/OFE Opinion and Order 368, issued January 11, 1990.

Further, if these projects do not go forward, the potential for future expansion of their capacity will be lost. This expansion potential represents an opportunity for domestic producers to access our growing markets.

There has been an extensive and exhaustive review of Iroquois in an adjudicatory proceeding before the New York State Public Service Commission (PSC) under Article VII of the Public Service Law. The PSC found that need for new gas supplies is well documented, that the approved route represents minimal adverse impact on the environment, and that the gas will be priced competitively, as stated in Opinion and Order Granting Certificate of Environmental Compatibility and Public Need, Issued December 8, 1989.[2] This record was provided to both FERC and the Department of Energy (DOE) for use in the federal proceedings.

The Iroquois project also is vital to New York because it provides a new underwater link to Long Island and ties into major interstate pipelines serving the Northeast. This will ensure the operational flexibility of the pipeline infrastructure serving the Northeast which will provide options for domestic producers to increase sales to the Northeast region.

Interstate pipelines historically have had problems delivering to the Northeast because of its location at the end of their systems. These deliverability problems have been critical in winter, making security of supply a major impediment to expansion of markets in the region. There are also deliverability problems on some systems in the summer months, often related to storage refill requirements, that have limited the growth of summer sales.

The Iroquois project will strengthen the Northeast pipeline infrastructure, expanding options for delivering gas, and enhancing the security and stability of winter supply to the Northeast. The Iroquois-Tennessee facilities will make available capacity on existing pipelines delivering gas from the Southwest, creating opportunities for increased domestic deliveries to Northeast markets.

Further, Iroquois will enhance the ability of existing pipelines to serve summer markets, such as sales for electric generation. This is important because growing concerns over air emissions are increasing emphasis on gas use in the summer for this purpose.

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[2] This decision was made after 11 days of public hearings and 45 days of evidentiary hearings at which more than 80 witnesses contributed to a record of 10492 pages with 232 exhibits.

Efforts continue to expand domestic gas deliveries to the Northeast. As mentioned above, the proposed ANR project recently was expanded and the Empire State Pipeline project is under review in New York State. In January of this year, a delegation of Oklahoma natural gas suppliers met with Northeast gas companies and state officials in Boston to explore market opportunities. These efforts will continue, but without increased expandable pipeline capacity increased gas deliveries to the Northeast can not occur.

Your consideration of these issues in pursuing a diversified strategy which allows a competitive market for domestic and Canadian natural gas will be greatly appreciated.

Sincerely,

William D. Cotter

William D. Cotter
Commissioner

Peter Bradford

Peter Bradford
Commissioner

WDC/ai

THE COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF CONSUMER AFFAIRS AND BUSINESS REGULATION

DIVISION OF ENERGY RESOURCES
100 Cambridge Street, Room 1500
Boston, Massachusetts 02202
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Michael S. Dukakis
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Paul W. Gromer
Commissioner

SENATE COMMITTEE
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MAY 2 1990
WASHINGTON, D.C. 20510

May 1, 1990

The Honorable J. Bennett Johnston, Chairman
Senate Committee on Energy & Natural Resources
SD-364
Washington, D.C. 20510

Dear Senator Johnston:

I am writing to you in my dual capacity as the Commissioner of the Massachusetts Division of Energy Resources and the Chairman of the Massachusetts Energy Facilities Siting Council. I understand that the Senate Committee on Energy and Natural Resources has scheduled a hearing on May 3, 1990 to discuss the certification of the proposed Iroquois Gas Transmission System, now pending before the Federal Energy Regulatory Commission ("FERC") in Docket No. CP89-634-000, and the recent Department of Energy ("DOE") decision to approve the applications of a number of Northeast gas utilities to import Canadian gas to the Northeast U.S. via the Iroquois pipeline.

I write to comment on the issues that you raised in your letters to the invited speakers and to urge you to oppose any efforts to delay or cancel the proposed Iroquois Pipeline project through the employment of protracted and unnecessary evidentiary hearings before FERC.

In your letters to Chairman Allday of FERC, Secretary Watkins of DOE, Mr. Reid of Iroquois, and Mr. Hilliard of the Independent Petroleum Association of America ("IPAA"), you raise the following as topics for discussion at the May 3rd hearing: (1) whether issues raised by intervenors in the Iroquois proceeding at FERC constitute material issues of fact which must be addressed in a full evidentiary hearing by expert testimony subject to cross-examination; (2) whether the contractual arrangements and/or rate design of the upstream transportation and sale of Canadian gas that will be transported on the proposed Iroquois pipeline gives this gas an unfair competitive advantage over potential domestic gas suppliers; (3) the incremental need for the Iroquois volumes and the adequacy of pipeline capacity to transport domestic natural gas to the

Northeast; and (4) the propriety of Opinion and Order No. 368 in which DOE conditionally authorized the importation of Canadian natural gas via the Iroquois pipeline by a number of gas utilities in the Northeast. I address each of these topics in turn below.

With regard to the first issue, FERC has already held extensive hearings on the Iroquois project which have dealt with such matters as market need, facilities sizing, and rates. In addition, Iroquois has filed voluminous supporting documentation with FERC. Intervenors have had a full and fair opportunity to advocate their positions with regard to these matters, both in writing and at FERC hearings, in the more than three years since the Iroquois application was initially filed at FERC. The Iroquois project has undergone a thorough environmental review at both the state and federal levels. I am therefore confident that FERC currently has a more than adequate basis for issuing a decision on the certification of the project. Evidentiary hearings at this time would serve no practical purpose and could potentially delay the Iroquois project to the point where its viability may be placed in jeopardy.

In this regard, I must disagree with the suggestion that FERC must hold additional hearings in order to comply with former Chairman Hesse's pledge to allow all interested parties an ample opportunity to address the merits of all public interest issues. In fact, all interested parties have had numerous opportunities to address such issues and the arguments of all parties are well represented in the record. FERC clearly has lived up to Chairman Hesse's pledge and the case is now ripe for a decision. The public interest will be served by prompt FERC action on certification, not by unnecessarily rehashing the facts of the case ad infinitum.

With regard to the second issue, I know of no special contractual arrangements for Canadian gas supply that could not be matched by domestic suppliers. One of the major attractions of Canadian gas, particularly for the cogeneration and Independent Power Producer ("IPP") market, has been the willingness of Canadian producers to sign long-term (15 to 20 year) supply contracts with a commodity price escalator indexed to the price of a market basket of competing fuels. Cogeneration projects often require this type of fuel supply contract in order to obtain financing. I understand that domestic producers generally have been unwilling to sign such contracts. These contractual arrangements are a clear example of suppliers competing to meet the needs of the market, and cannot be characterized as an unfair trade practice.

The second part of this issue relates to the differences in pipeline transportation rate structure between the U.S. and Canada. The rate structures of the two countries each consist of a demand charge (fixed cost) component and a commodity charge (variable cost) component. The Canadians, however, include a greater percentage of total costs in the demand charge. As a result, if total delivered gas costs to a given customer are equal, the Canadian gas would be dispatched first because of the lower incremental costs to the customer. This issue has been debated for a number of years. I believe that it would make sense for the two countries to have an equivalent rate structure. However, this issue should be resolved on a generic basis in joint discussions between FERC and the Canadian National Energy Board ("NEB") and in generic hearings before those organizations. The U.S. and Canadian pipeline transportation rates for the Iroquois volumes are in accordance with current FERC and NEB policies. It would make little sense to attempt to address generic rate structure issues within the context of any FERC proceeding for an individual pipeline proposal. Any attempt to introduce this issue in the Iroquois proceeding is merely a pretext to delay the project.

With regard to the third issue, there can be no doubt about the Northeast's need for the Iroquois volumes. Indeed, the need for the Iroquois supplies has been adequately demonstrated by the existence of solid, long-term agreements to purchase the gas by a large number of shippers in the Northeast, including gas utilities, electric utilities, and cogeneration and IPP facilities. More generally, this need has been attested to in detail on many occasions by local gas consumers and Northeast state officials before FERC, the NEB, Congress and countless other forums. Numerous studies have concluded that the gas needs of the Northeast will continue to grow rapidly and that new supplies, including and in addition to those being transported by Iroquois, will be required over the next few years. Much of this growth is expected to occur in the electric power sector, as existing plants convert to gas for environmental reasons and as new gas-fired cogeneration and IPP facilities are built. A large expansion in the gas pipeline capacity serving the region is a critical prerequisite to meeting regional electric demand growth in an environmentally acceptable manner, as well as meeting demand growth in traditional customer sectors.

The construction of additional pipeline capacity to provide increased natural gas supplies to the Commonwealth is a cornerstone of Massachusetts' energy policy. Increased supplies of natural gas would confer numerous benefits to the Commonwealth, including increased fuel diversity and energy security, substantial environmental benefits, such as reduced emissions of pollutants which cause acid rain and contribute to global warming, and enhanced inter- and intra-fuel competition, resulting in lower prices for consumers. The proposed Iroquois pipeline is the single largest source of incremental gas supplies for Massachusetts and thus represents a critical element in ensuring that the citizens of the Commonwealth are able to realize the benefits of additional natural gas supplies in a timely fashion.

A number of local gas utilities and power generators are depending on these gas supplies. If the project is delayed, the consequences could be dire for the New England energy situation. Gas utilities may be constrained from adding new customers. New gas-fired cogeneration and IPP projects, which we are depending on for a significant share of our growing electricity needs, would be delayed or cancelled. Existing power plants that are slated for conversion to natural gas would be prevented from doing so, thereby seriously impairing our efforts to ameliorate our acid rain and other environmental problems. The Northeast would become more dependent on imported oil, thereby exacerbating regional and national concerns regarding energy security.

It is critically important to recognize that the construction of the Iroquois project and increased sales of domestic gas to the region are not mutually-exclusive. In fact, more than one billion cubic feet daily of new capacity to transport domestic gas to the Northeast is expected to come on line in the near future as the result of FERC's "open season" proceeding. In addition, ANR Pipeline Company is reportedly examining the possibility of using the Iroquois pipeline or the now dormant Champlain pipeline to transport domestic supplies, possibly including the use of their Michigan storage fields. The market for natural gas in the Northeast will be growing rapidly over the next decade. Domestic producers will have many opportunities to significantly expand their sales to this market.

With regard to the fourth and final issue on the hearing agenda, I fully support DOE's decision, set forth in Opinion and Order No. 368, to conditionally approve the importation of a significant portion of the gas to be transported by Iroquois. In making this decision, DOE recognized the overriding public interest benefits of approving these volumes in a timely fashion in order to meet the rapidly growing needs of the Northeast market for additional gas supplies. It would clearly have been inconsistent with the spirit of the U.S.-Canada Free Trade Agreement for DOE to have rejected these import applications or to have attempted to alter fairly negotiated contractual arrangements between buyers and sellers.

In closing, new natural gas supplies, from both the U.S. and Canada, are of critical importance in securing a reliable, least-cost and environmentally sound energy future for Massachusetts and the other states in the Northeast. The Iroquois Pipeline would be an important conduit for such supplies and I urge you to oppose any efforts to derail the project. FERC and DOE have acted appropriately. The request of certain intervenors for additional evidentiary hearings is without merit and appears to have the sole purpose of delaying and perhaps killing the project, an outcome that gas and electricity consumers in the Northeast cannot afford.

Thank you for your consideration of these comments.

Sincerely,

Paul W. Gromer
Commissioner of Energy Resources
Chair, Energy Facilities Siting
Council

cc: Chairman Martin Allday, FERC
Secretary James D. Watkins, DOE
Mr. Robert Reid, IGTS
Mr. C. Paul Hilliard, IPAA
Massachusetts Congressional Delegation

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EC

STATE OF NEW HAMPSHIRE

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April 26, 1990

SENATE COMMITT
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MAY 3 1990
WASHINGTON, D.C. 2051

The Honorable J. Bennett Johnston
U.S. Senate
Chairman, Committee on Energy and Natural Resou
SD-364
Washington, D.C. 20510

Dear Senator Johnston,

It has been brought to our attention that you have scheduled oversight hearings regarding applications to import Canadian natural gas to the markets of the northeast.

Increased supplies of natural gas are essential to New Hampshire. Although we are a relatively small consumer when compared to our southern neighbors, our local distribution companies reach approximately 20% of the state, and provide nearly 13% of our energy needs. Our customers annually consume approximately 13,500 BCF, and we have seen a 25% increase in gas sales since 1985.

The "open season" process which was instituted by the FERC in 1987, and which considered the Iroquois project among the contenders to serve the New England market, was of particular interest to New Hampshire. We are situated at the extreme end of the U.S. gas transmission pipeline, and we are vulnerable to the changing supply conditions that weather, pipeline constraints, and external customer demands may impose on our customers. While our serving companies have an excellent service record, we envision the open season process as an opportunity to augment and enhance that single supply source.

New Hampshire's natural gas requirements continue to increase. It is our view that, even with the addition of a project such as Iroquois, our demands will continue to exceed the supply options which have thus far been brought to the table. If natural gas becomes a boiler fuel for future electric generation in New England, then our requirements will certainly exceed all known supplies.

New Hampshire needs gas immediately. On peak days, we are dependent on as much as 50% of our supply from non-pipeline peak shaving facilities. Projects such as Iroquois, which have already withstood the tests of much state and federal analysis, can be brought into service in a timely manner to alleviate the supply shortages which currently exist. With these quantities in hand, we will be able to solicit even more gas from other sources to meet a continually expanding gas market.

Sincerely yours,

Larry M. Smukler

Larry M. Smukler
Chairman

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION
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Providence, R.I. 02903

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SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
RECEIVED
MAY 3 1990
WASHINGTON, D.C. 20510

Hon. J. Bennett Johnston, Chairman
United States Senate
Committee on Energy and Natural Resources
SD-364
Washington, DC 20510

Dear Senator Johnston,

I am writing in regard to the hearing which you are holding on May 3 on the subject of natural gas supplies to the northeast. I am concerned that since no representative from a northeast state will appear before your committee, that you and the other committee members may not be sufficiently cognizant of the great importance we attach to this matter. I will be deeply appreciative of your attention to this means of communication.

The State of Rhode Island has long had a vital interest in increasing the supplies of natural gas to the state and to our region. The state intervened in the open season dockets, and has actively supported and welcomed the projects involving domestic and Canadian supplies which finally emerged from this proceeding.

As you are well aware, the need for new electric power generation in New England is acute. Even with Seabrook at full operating capacity and with extensive conservation and load management programs, we must build new power plants. Rhode Island's energy policy, which integrates environmental and energy requirements, looks to natural gas for power generation as well as direct use. A delay beyond 1991 of the Iroquois volumes would have a serious effect on the ability of New England utilities to provide needed electricity, and, with another cold winter, could also strain available capacity for home heating and commercial and industrial use.

Power plants cannot be financed absent long term gas contracts. Only the Canadian producers have been able to assure such arrangements with northeast distribution companies and power plant developers. But the current export licenses for much of this gas will expire if Iroquois is not constructed and in operation by October 1, 1991. Many of the contracts were executed during what could be termed a buyer's market. In my view, this will not soon recur.

Including the imports to be brought in through the Iroquois facilities, gas supplies to our area will still be almost 85%

domestic. We do not believe that this ratio will change substantially. As the market grows, domestic producers will continue to find a welcome here. Canadian gas will not dominate our market. Indeed, future exports from Canada to our region may well be severely limited. In a speech in February to the Gas Committee of the National Association of Regulatory Utility Commissioners, Kenneth Vollman of the Canadian National Energy Board stated that projections of sustainable Canadian export yields are actually lower than proposed expansion plans. Also, we are observing that other markets, notably California, appear to be more attractive to Canadian producers.

In summary, we see the Iroquois project as an important window of opportunity to greatly improve our energy mix, reduce our continued high reliance on imported oil, help solve air quality problems, and provide fuel for critically needed electric generation.

The Federal Energy Regulatory Commission's unanimous, positive action on the Niagara Import Point Project was a heartening sign that the regulatory body charged with the responsibility and authority in this matter, after long study and careful consideration of all of the issues you are raising in this hearing, could decide in favor of the NIPS facilities involving Canadian imports. That decision was of crucial importance to our state, as the volumes included those for Ocean State Power II, a 250 megawatt combined cycle power plant currently under construction in Rhode Island and due to commence operation in 1991. The Commission's NIP's order makes it clear that the rate design concerns of the domestic producers can be addressed in individual pipeline rate proceedings.

We look forward to the FERC's decision, of equal importance to us, on the Iroquois volumes. I respectfully urge you to allow the regulatory process to proceed unhindered.

Thank you very much for your attention. A vital aspect of the energy future of our region is at stake here, and I ask that you give due consideration to our concerns.

Sincerely,

James J. Malachowski
Chairman

cc Senator John Chafee
Senator Claiborne Pell
Representative Ronald Machtley
Representative Claudine Schneider

Kenneth Gordon
Chairman

Cheryl Harrington
Elizabeth Paine
Commissioners

PUBLIC UTILITIES COMMISSION

May 1, 1990

Honorable J. Bennett Johnston, Chairman
Energy and Natural Resources Committee
United States Senate
Washington, D.C. 20515

Dear Senator Johnston:

It has just recently come to my attention that the Senate Committee on Energy and Natural Resources will be conducting an oversight hearing on May 3, 1990 regarding applications for authorization to import Canadian Natural Gas over the Iroquois Pipeline system. I note that you have invited Mr. Robert Reed of Iroquois Gas Transmission System, F.E.R.C. Chairman Allday, Energy Secretary Watkins and Mr. C. Paul Hilliard of the Independent Petroleum Association of America to testify. However, neither LDC's nor gas using electricity producers appear to be represented.

The matter of gas imports from Canada is particularly critical to customers in the northeastern United States, including the State of Maine. As a simple inspection of our geography will confirm, we must remain alert to opportunities to obtain natural gas from our neighbors in Canada as well as from the gas producing regions of the United States. We are concerned that we have available to us, on fair terms, gas supplies from anyone who wishes to reach our markets.

The Power Planning Committee of the New England Governors' Conference has been actively engaged over the years in attempting to assure adequate supplies of natural gas for New England, both for local distribution customers and for the burgeoning market in electricity generation. We reach out to all potential suppliers, regardless of location. I am concerned that no impediments be placed in the path of this development.

Although the time is short before your hearing I strongly urge that you invite a representative of the New England Governors' Conference Power Planning Committee to present testimony on New England's gas needs before your Committee. In this way you should receive a more complete picture, from the ratepayer and customer end of the spectrum, on New England's

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views of the desirability of gas supplies, whether from Canada or the United States. I am confident that a Commissioner or other representative of the New England Governors' Conference could be present at the Committee's hearings. I would urge you most strongly to take this opportunity to hear New England's views on these matters.

Sincerely,

Kenneth Gordon
Chairman

KG/bp

cc: Commissioner Cheryl Harrington
Commissioner Elizabeth Paine
Steve Leahy, New England Governors' Conference
Bruce Ellsworth, Chairman, Power Planning Committee
Gas Task Force

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The Brooklyn Union Gas Company
195 MONTAGUE STREET
BROOKLYN NEW YORK 11201-3631

EDWARD J. SONDEY
VICE PRESIDENT

May 1, 1990

SENATE COMMITTEE
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MAY 1 1990
WASHINGTON, D.C. 20510

Hon. J. Bennett Johnston,
Chairman
Committee on Energy and
Natural Resources
United States Senate
Washington, D.C. 20810-6150

Dear Senator Johnston:

We understand that the Senate Energy and Natural Resources Committee will hold an oversight hearing on May 3, 1990 at which James D. Watkins, Secretary of the United States Department of Energy, Martin J. Allday, Chairman Federal Energy Regulatory Commission (FERC), Robert Reid, President of Iroquois Gas Transmission System (IGTS), and C. Paul Hilliard, Chairman of the Board of the Independent Producers Association of America (IPAA) have been invited to testify. We further understand that the Energy Committee's inquiry will focus on proposed imports of natural gas to be transported on the IGTS system and alleged anti-competitive disparities in the manner in which Canadian and domestic natural gas supplies are priced. While your Committee has not invited representatives of IGTS shippers or natural gas consumers in the Northeast region of the United States to testify at the May 3rd hearing, the undersigned local distribution company (LDC) shipper customers of IGTS submit that the Energy Committee's hearing record would not be complete without considering the views of IGTS shippers on crucial aspects of the "controversy" raised by IPAA, as well as considering certain unique benefits of the IGTS system that we believe may otherwise be overlooked.

IPAA's opposition to Canadian natural gas import projects in general and the IGTS system in particular is founded upon a patently false premise: that perceived differences in the manner in which Canadian and domestic supplies of natural gas are priced may place U.S. producers of natural gas at a competitive disadvantage. IPAA's allegations of anti-competitive pricing apparently have arisen from IPAA's perception that Canadian producers and Canadian and U.S. transporters of imported natural gas are recovering, through fixed charges, costs that would have to be included in the commodity component of rates that LDCs pay if the gas were sold by a domestic producer.

There is no factual or logical basis for IPAA's allegations of unfairness. First, the Committee should be aware that many U.S. producers and pipelines that sell natural gas have adapted their contracts to current market realities including competition with Canadian suppliers~~.~~ -- Two of the three major interstate pipelines, that serve the Northeast and other markets have adapted to current market realities by incorporating gas inventory charges (GIC) or equivalent charges into the terms and conditions of their long term firm sales services, and the third has a GIC proposal pending before FERC. These GIC charges are designed to assure minimum purchases of pipeline supplies of natural gas or to provide a fund to discharge pipelines' take-or-pay obligations to producers if minimum purchase levels are not met.

U.S. producers and other domestic marketers of natural gas also have been successful in incorporating fixed supply reservation charges in contracts for new long term firm gas sales to LDCs, including many of the undersigned LDC companies. Under such supply reservation charges, the purchasers typically pay a negotiated portion of the price through a fixed monthly charge. Significantly, sales reservation charges are not incorporated in the Canadian gas supply import arrangements conditionally authorized by the DOE in Opinion and Order No. 368. If, despite these innovations in domestic gas markets, IPAA members feel that domestic pipeline rate design methods render domestic natural gas non-competitive, the appropriate forum in which to raise such concerns is in FERC's ongoing review of interstate pipeline rate designs in connection with FERC's Rate Design Policy Statement. IPAA's members are free to seek whatever changes in rate design on the pipelines serving the Northeast they consider appropriate. For these reasons, IPAA's allegations of unfair and anti-competitive pricing and contentions that IGTS's certificate application should be set for hearing are groundless and without merit.

The Committee also should be aware that on numerous occasions since 1988 representatives of several of the undersigned IGTS shippers have met with IPAA in efforts to reach agreement in principle on long term gas supply arrangements. Many of these IGTS shippers offered to purchase long term firm gas supplies from IPAA's members on terms and conditions that potentially were more favorable to IPAA members than the terms now reflected in actual contracts with Canadian suppliers. Despite discussions regarding the inclusion of supply reservation charges in long term gas supply contracts with IPAA producers, its members refused to sell gas to these LDCs on a long term basis or to provide meaningful corporate guarantees of performance -- indispensable commitments that

Hon. J. Bennett Johnston
May 1, 1990
Page 3

Canadian as well as numerous domestic suppliers have made to IGTS shippers. Accordingly, it is apparent that IPAA's opposition to IGTS and other import projects are not prompted by any structural deficiencies in natural gas markets or U.S. regulatory policies favoring imported natural gas. Instead, IPAA apparently is seeking to distort the actual marketplace conditions for long term, reliable energy supplies by going outside normal regulatory procedures with the apparent goal of delaying or otherwise disrupting a badly needed gas supply project. Your Committee should reject and condemn such efforts.

The Committee also should be aware of the unique benefits IGTS offers for long term energy security in the Northeast. For too many years the Northeast energy markets have been characterized by an undue reliance upon imported fuel oil and an unmet demand for additional supplies of competitively-priced natural gas. In an effort to address these problems, FERC instituted an "open season" certificate application procedure specifically for Northeast markets. Through a series of FERC orders identifying discrete projects and settlements, some of the most critical, near term firm service needs were met. It is worth noting that more than half of the incremental volumes of natural gas for new already certificated "open season" gas supply projects proposed to serve Northeast markets will be obtained from domestic suppliers and marketers.

Despite FERC's efforts to date, the IGTS shippers have substantial additional, predominantly high priority market demand that must be served by the 1991-92 winter heating season. IGTS is the only viable existing project that can meet the critical demands of all IGTS shippers. For example, no other project proposes to provide service to upstate New York and all of the markets IGTS proposes to serve in Connecticut, Massachusetts, and New York. The need for the supplies to be delivered by IGTS cannot be doubted. FERC Staff has collected voluminous material from the affected LDCs that confirms the IGTS shippers' urgent need for incremental gas supplies. In addition, because existing delivery facilities for the three undersigned New York metropolitan area companies are operating at capacity, expanding the transmission capacity of New York City's traditional pipeline suppliers -- Transco, Texas Eastern, and Tennessee -- is not a feasible alternative to IGTS. Construction of the IGTS system will obviate the need for extremely costly, time consuming additions to the pipeline distribution facilities serving the New York metropolitan area. New Jersey markets proposed to be served by IGTS will obtain similar benefits.

Rather than opposing IGTS, IPAA should support this project. Construction of the IGTS system will permit new gas markets in the Northeast to develop and grow, to the long term benefit of all natural gas supplier including IPAA. Moreover, increased use of efficient and environmentally beneficial natural gas in the Northeast will serve to bolster the economic development of this region. In sum, long term considerations underscore the wisdom of authorizing the IGTS project.

Finally, we are concerned that the nature and scope of your Committee's proposed inquiry. As it may be directed to DOE Secretary Watkins and FERC Chairman Allday, the oversight hearing may tend to compromise the independent deliberative processes of the DOE and FERC. For example, matters such as the need for IGTS and FERC's intended disposition of pending motions for evidentiary hearings have been the subject of many detailed submissions and pleadings by all concerned parties. These matters properly are before FERC. We trust that the Committee will cooperate with Secretary Watkins and Chairman Allday in maintaining the integrity of the ongoing FERC and DOE decisional processes, consistent with the judicially recognized principle that Congress should not intervene in an administrative agency's deliberative functions.

We appreciate your taking the time to consider our views.

Very truly yours,

THE BROOKLYN UNION GAS COMPANY

By: Edward Sondey
Edward J. Sondey, Vice President

AND ON BEHALF OF:

BOSTON GAS COMPANY
CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CONNECTICUT NATURAL GAS CORPORATION
CONSOLIDATED EDISON OF NEW YORK, INC.
GRANITE STATE GAS TRANSMISSION, INC.
LONG ISLAND LIGHTING COMPANY
NEW JERSEY NATURAL GAS COMPANY
THE SOUTHERN CONNECTICUT GAS COMPANY
YANKEE GAS SERVICES CORPORATION

OFFICIAL COMMITTEE FILE
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EC

The Commonwealth of Massachusetts
Department of Public Utilities
100 Cambridge Street — 12th Floor
Boston, Massachusetts 02202

(617) 727-3500

MAY 0 1 REC'D

April 30, 1990

ERGY AND NATURAL RESOU
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MAY 2 1990
WASHINGTON, D.C. 2051

Honorable J. Bennett Johnston, Chairman
United States Senate
Committee on Energy and Natural Resources
SD-364
Washington, DC 20510-6150

Dear Senator Johnston:

The Department of Public Utilities of the Commonwealth of Massachusetts ("Department or MDPU"), an arm of the executive branch of the Massachusetts state government, submits these comments for the oversight hearing being conducted by the Senate Committee on Energy and Natural Resource ("Committee") regarding applications for the authorization to import Canadian natural gas to serve the northeast U.S. and for the construction and operation of the Iroquois Gas Transmission System natural gas pipelines to deliver such gas to the northeast.

As a preliminary matter, the Department would urge the Committee to invite appropriate members of governmental agencies from affected northeast states to testify before the Committee on the implications of the Iroquois project for their states' economic and environmental well-being.

The Department's interest in the successful outcome of the Federal Energy Regulatory Commission's ("FERC") so-called "open season" process, which comprised 31 pipeline proposals to bring additional supplies of gas to the northeast, is long-standing and well-documented. Throughout the open season process, the Department, as part of the Massachusetts Governmental Intervenors ("MGI"), has noted the critical need for additional supplies of natural gas to meet the state's energy requirements.

As the Committee is no doubt aware, Massachusetts and the New England region generally are situated at the end of the pipeline system in the U.S. northeast. Historically, this situation has led to several undesirable outcomes. These include the lack of access to optimal quantities of pipeline gas supplies, heavy reliance on costly supplemental peaking fuels such as propane and liquefied natural gas ("LNG"), and constraints on the operational flexibility of pipelines and local distribution companies ("LDCs") in the region. Given the difficulties that New England has faced in obtaining adequate supplies of natural gas it comes as no surprise that New England is more dependent on imported oil than any other region of the country.

As the Department has consistently maintained throughout the open season process, there is a pressing need for substantial new amounts of natural gas in Massachusetts. According to the 1988 forecast of the Massachusetts Energy Office, demand for natural gas in the Commonwealth is expected to grow at an average annual rate of 5.2 percent. The Massachusetts Energy Office anticipates the need for additional pipeline capacity to deliver at least 300 to 400 million cubic feet a day ("Mcf/d") of incremental gas supplies by the early 1990s. The lion's share of the incremental gas demand will be required to fuel new electric generation facilities that are critical to meet the state's growing electricity demand.— This pipeline capacity is also needed because existing capacity is fully utilized during the peak winter heating season. The extremely tight gas supply situation during the extended cold snap in December 1989 made the peril of this capacity constraint quite clear.

New gas supplies to the region, as reflected in the Iroquois project, will help to lessen Massachusetts' dependency on imported oil, add to the diversity of the fuel mix in the region, and help to serve the growing energy needs of businesses and consumers in New England. By increasing the proportion of natural gas in the total energy mix of the state, projects such as Iroquois will also provide significant environmental benefits. As the Committee knows from the ongoing efforts in Congress to amend the Clean Air Act, natural gas is far less polluting than other fossil fuels. Enhanced use of natural gas would help to diminish the region's role in the formation of acid rain (from SO_2 emissions) and production of so-called greenhouse gas emissions (from CO_2 emissions principally).

The Iroquois Pipeline will supply 577.8 Mcf/d of natural gas to local distribution companies ("LDCs") and electric power generation facilities in the Northeast. Of this amount, 176.1 Mcf/d will be delivered to Massachusetts, mostly to Boston Gas Company, Granite State Gas Transmission, Inc./Bay State Gas Company, Colonial Gas Company, Essex County Gas Company, and New England Power Company. Approximately 50 percent of these volumes are targeted for the electric generation market, which is itself growing 2.0 percent a year in New England.

The Iroquois Project will satisfy only about 40 percent of Massachusetts' identified incremental gas demand in the near term. This brings up two points. First, to the extent that domestic producers wish to sell additional gas in the northeast market there appears to be a need for natural gas supplies beyond those offered by the Iroquois project and, therefore, considerable opportunities for gas merchants to market gas from sources on both sides of the border. Second, since the Iroquois volumes will not satisfy the full expected requirements of the market, any unnecessary delay in the Iroquois project would seriously damage Massachusetts' ability to meet its immediate energy needs, with potentially severe consequences for the economic and environmental well-being of the region.

The questions which the Committee placed before the witnesses in this hearing suggest that the Committee intends to review the manner in which FERC and the Department of Energy ("DOE") have exercised their regulatory review functions with respect to Canadian gas imports and the Iroquois project. The Department would note that FERC and DOE have employed successful procedures to review these matters in a balanced, yet expeditious fashion. Although FERC initially cautioned that the resolution of open season dockets could take up to five years, the FERC has listened to the demands of the marketplace in calling for new gas pipeline capacity afforded by projects like Iroquois. FERC approved workable settlements for a number of open season projects -- without the need for formal, drawn-out evidentiary hearings.

Any suggestions that the regulatory review of the open season projects has not been thorough are misplaced. In assessing the need for new pipeline capacity to serve the Northeast both FERC and DOE have received and reviewed an abundance of data which document such requirements. On the siting and environmental issues surrounding the open season projects, FERC has recently issued Draft Environmental Impact Studies.

In addition to the economic and environmental review of federal regulators, northeast states such as Massachusetts have been extremely active in evaluating the economics and siting issues surrounding open season projects such as Iroquois. In a recent case before the Department, Boston Gas Company sought Department approval to secure a long-term gas supply contract with a major Canadian producer for delivery on the Iroquois pipeline. After an extensive review of the producer contract and the arrangements for transportation of such gas the Department approved the contract finding it both beneficial to existing ratepayers and a necessity for serving new retail and electric generation markets.

On the environmental front, the Massachusetts Energy Facilities Siting Council has filed extensive environmental comments on the open season projects and has held numerous public hearings within the state in towns affected by open season construction. Throughout the entire open season process, both at the federal and state levels, there has been an extensive and thorough discussion of all aspects of the projects.

The suggestion that FERC conduct trial-type evidentiary hearings on the Iroquois project or otherwise subject Iroquois to yet another level of regulatory review would entail a costly delay in the acquisition of energy supplies needed for the economic and environmental well-being of the Commonwealth. The Department submits that such a course of action would be extremely ill-advised and should not be undertaken.

Sincerely,

Bernice K. McIntyre, Chairman

Robert N. Werlin, Commissioner

Susan F. Tierney (D.E.B)
Susan F. Tierney, Commissioner

cc: Governor Michael S. Dukakis
Secretary of Consumer Affairs, Mary Ann Walsh

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MAY-02-1990 13:05 FROM NH PUBLIC UTIL COMM TO 916172272690 P.06

STATE OF NEW HAMPSHIRE
OFFICE OF THE GOVERNOR
JUDD GREGG, GOVERNOR

April 30, 1990

The Honorable J. Bennett Johnston
U.S. Senate
Chairman, Committee on Energy
and Natural Resources
SD-364
Washington, DC 20510

Dear Senator Johnston:

I am advised that you have invited responses from selected industry and federal officials regarding applications to import Canadian natural gas to northeast markets. Please allow me to offer my own position on that issue.

New Hampshire needs additional natural gas. Our economy continues to grow and our gas distribution companies advise me that because of limited pipeline supplies, they require increasing amounts of peak shaving gas during critical winter periods to meet their customer demands. Prospective electric generating producers propose to use off-peak gas during non-winter periods.

We are currently dependent upon a single pipeline for our gas supply. The addition of a project such as Iroquois will allow for more diversity in the gas market and less vulnerability to interrupted gas flows.

Our experience gives us confidence that the FERC open season review will adequately address environmental and supply issues from a federal perspective. I encourage you to allow that process to continue, and to hold the FERC to their regulatory commitments.

At the state level, we also have comprehensive review processes to explore gas requirements, purchasing options under which needs can be met, and environmental impacts which those options may have on our communities. I suggest that our processes, together with those of the FERC, will allow all parties to address the issues which you have raised, and will provide a record which might only be duplicated by your own thorough investigation. Our records will be available to assist you in any way that you find helpful.

Sincerely,

Judd Gregg

Judd Gregg
GOVERNOR

New England Electric

John W. Rowe
President and Chief Executive Officer

New England Electric System
25 Research Drive
Westborough, Massachusetts 01582
Tel. (508) 366-9011 TWX710-390-0732
Cable: NEELECSYS WTBO

May 2, 1990

The Honorable J. Bennett Johnston
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D. C. 20510

OFFICIAL COMMITTEE FILE
PLEASE RETURN

Dear Mr. Chairman:

This letter is prompted by your May 3, 1990 hearings on matters affecting natural gas for the New England region. In summary, it expresses our concern that steps might be taken to delay FERC action on pending applications to expand pipeline capacity to bring additional U.S. and Canadian natural gas to the northeastern U.S.

As explained below, we believe that domestic gas producers' concerns about about competition from Canadian natural gas does not reflect a full understanding of factors affecting the competitiveness of gas from U.S. vs. Canadian sources. We also believe that actions to block expansion of pipeline capacity, including the Iroquois pipeline, would serve to limit rather than expand opportunities for natural gas to play a larger role in supplying U.S. energy demands.

Our Interest in Obtaining Additional Natural Gas.

New England Power Company (NEP), a subsidiary of the New England Electric System, is engaged in the generation and transmission of electric power for sale at wholesale in the New England region. It serves over 1.25 million electric consumers through sales to affiliated and unaffiliated utilities, and is a major source of power to the New England Power Pool.

NEP currently utilizes natural gas to generate only about 1% of its electric power. However, NEP has contracted with six interstate pipeline companies and TransCanada to obtain 190,000 Mcf per day of firm capacity to transport substantial new supplies of natural gas in order to:

. Diversify its fuel sources and reduce dependence on imported oil;

. Comply with the Massachusetts Acid Rain Law; and

. Provide gas needed for an efficient, repowered generating plant (now oil-fired) in Providence, Rhode Island.

The name "New England Electric System" means the trustee or trustees for the time being (as trustee or trustees but not personally) under an agreement and declaration of trust dated January 2, 1926, as amended, which is hereby referred to, and a copy of which as amended has been filed with the Secretary of the Commonwealth of Massachusetts. Any agreement, obligation or liability made, entered into or incurred by or on behalf of New England Electric System binds only its trust estate, and no shareholder, director, trustee, officer or agent thereof assumes or shall be held to any liability therefor.

Based upon transportation applications presently pending before FERC, NEP is seeking to obtain about two-thirds of its gas supplies from U.S. sources and one-third from Canada.

Domestic Producer Concerns about Rate Design.

We understand that domestic gas producers are concerned that rate design applicable to Canadian pipelines provides an unfair competitive advantage for Canadian over domestic gas suppliers. In fact, our evaluation shows that Canadian transportation rate design reduces the competitiveness of Canadian gas. Canadian rate design requires the payment of higher fixed monthly charges (i.e., demand charges) compared to the modified fixed variable rate design applicable to most U.S. pipelines.

In evaluating new incremental supply opportunities, gas purchasers (such as NEP) view high demand charges as an added risk when making long-term commitments. In contrast, current U.S. rate design with lower demand charges gives a competitive advantage of domestic producers since it provides a strong incentive to pipelines to provide attractively priced transportation services in order to maximize pipeline throughput.

NEP has contracted to purchase 60 million cubic feet of gas per day (out of a total average need for 190 million) from Canadian producers because these producers were willing to offer long-term (15-20 year) contracts with market-responsive pricing terms -- and without any special premium price. If TransCanada PipeLines had adopted a rate design similar to that utilized by U.S. pipelines, Canadian gas would have been more attractive to NEP.

Regulatory Delay Works Against Expansion of Gas Markets.

Delay in certificating new firm pipeline capacity to serve NEP and other customers in the Northeast would impede expansion of markets for natural gas. In NEP's case, applications pending before the FERC include facilities for domestic and Canadian gas that cannot be separated. Facilities covered by Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company applications would carry both domestic and imported gas for NEP. Also, delays in facilities certification to consider rate design issues would introduce new uncertainties about expanded use of natural gas.

Free Trade Commitments.

Adoption of the U.S.-Canada Free Trade Agreement was an important step forward. We believe the U.S. Government should not now act to discourage Canadian gas, reduce competition and disadvantage consumers.

In summary, I urge you to encourage prompt FERC approval of expanded pipeline capacity to bring additional U.S. and Canadian natural gas to the northeastern U.S. Expeditious action will contribute to the expansion of markets for natural gas and benefit consumers, gas producers and the environment, while reducing dependence on imported oil.

Sincerely,

mitchell group

1990 PM 3:44

May 4, 1990

Senator Johnson
Russell Office Building
Washington, D.C. 20515

SENATE
MAY 10 1990
RECEIVED
WASHINGTON, D.C. 2051

Subject: Proposed Iroquois Gas Transmission System
Newtown, Connecticut Region
Public Notice No. 13887-89-1123-64

Dear Senator Johnson:

We have developed several major reservations about the current intent of constructing a natural gas pipeline from Canada to Long Island. While we are sure that you have received many letters from impacted property owners and conservation organizations, we would like to include our concerns even though we are not directly impacted.

> The deforestation of a 100 foot clear cut for a two foot diameter line is extreme. This can very easily be done in a 25 foot easement at far less stress to the environment. We are also very concerned that Iroquois Gas will be able to lease or sell rights to use the easement right of way to other utilities without the need for additional environmental impact statements. Several existing rights-of-way could provide routes with considerably less impact on the existing environment.
>
> The current route of the pipeline will bring it across the Newtown Pootatuck Aquifer at a point very close to the main wells of the town. The EPA has named the aquifer as the "sole source aquifer" for the area. We are very concerned about the migration of contaminants along the trenchway into the aquifer. We have seen no consideration of this impact in any of the EIS submissions.
>
> Without the benefit of Evidentiary Hearings there can be no determination of need for this gas. The fact that there may be a market is not the same as proof that there is a need. We cannot understand how the project could have reached this level of development without these critical hearings being held and proof of this need being established.

six mile hill road p.o. box 753
newtown, ct 06470 · 203-270-1006

mitchell group

Iroquois Gas Pipeline
May 4, 1990
Page 2.

The purchase of foreign fuel at this time of sever federal debt should be cause enough for reconsideration. There are plentiful supplies of natural gas in the United States. We must be concerned about aiding the economic structure of the southern states which has been so recently depressed.

We have been told that the cost estimate for the pipeline has grown from the original $583 Million to over $2 Billion. The economic feasibility of spending that much money to obtain a foreign product whose need has not been established must be questioned in open meetings.

There is significant evidence that the routing of the pipeline was made with blatant disregard for the individual property owner and at the consideration of the large developer and their subdivisions. There are locations along the proposed route where individual homes will be demolished so that vacant tracts of land owned by developers will be preserved for future subdivision.

There is evidence that the developers were given advanced notice of the pipeline route long before it was made public and that their concerns were addressed at the expense of the individual property owner.

mitchell group

Iroquois Gas Pipeline
May 4, 1990
Page 3.

We have developed a deep concern in the entire process which has allowed the proposed pipeline to reach the level of development where some agencies and officials now consider it a foregone conclusion. There is a growing belief the health, safety and welfare of a significant number of people has been put in danger for a project of limited need and questionable feasibility.

We are available at your convenience to personally discus our concerns in this matter which is affecting so many families.

Thank you for your time,

Robert Mitchell

cc: Attached
File:GL\INGPIPE.001

IPAC

INDEPENDENT PETROLEUM ASSOCIATION OF CANADA
SUITE 700, 707 SEVENTH AVENUE S.W.
CALGARY, ALBERTA CANADA T2P 0Z2
TELEPHONE: (403) 290-1530
TELECOPIER: (403) 290-1680

June 8, 1990

Senator J. Bennett Johnston
Chairman
Senate Energy & Natural Resources Committee
364 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Mr. Chairman:

The Independent Petroleum Association of Canada ("IPAC") appreciates the opportunity to submit these comments for inclusion in the official Committee record regarding the Committee's "Oversight Hearing on Northeast Natural Gas Matters", held on May 3, 1990.

The hearing focused upon concerns expressed by U.S. independent producers that the U.S. regulatory process has failed -- procedurally and substantively -- to correct an alleged competitive advantage accorded Canadian natural gas with respect to incremental natural gas services to be provided U.S. Northeast consumers. With all due respect to our U.S. counterparts, IPAC respectfully submits that neither charge is accurate.

Procedurally, U.S. independent producers, fuel oil dealers, NIMBY's (Not In My Backyard), and other opponents of Iroquois have had, as Chairman Allday indicated, the opportunity to file testimony in the Iroquois proceeding. IPAA, among others, has done so.

The only procedural option that has thus far been denied is the use of a trial type proceeding. As FERC's General Counsel stated at the hearing, these type of "full-blown trial type hearing[s]" are rarely used in pipeline certificate proceedings, could take two to three years and thereby delay the Iroquois project, and should only be invoked if there is a compelling reason why a decision based on written submittals is inadequate. In the absence of such a rationale, U.S. consumers should not be frustrated in their desire and need for timely delivery of Canadian natural gas supplies through Iroquois.

Senator J. Bennett Johnston
June 8, 1990
Page Two

Substantively, the facts, as reviewed by FERC, DOE, and the Court of Appeals, simply do not comport with the allegation that Canadian producers are accorded an unfair competitive advantage as a function of the different rate designs deployed in Canada and the U.S. FERC itself, in its "NIPS" decision rendered one day prior to the Energy Committee hearing, conducted an analysis with respect to this precise issue. That analysis concluded that "any rate differential that exists between the Canadian and domestic transportation rates is no different than that which exists among various domestic pipelines seeking to compete in the marketplace; Canadian gas does not have an overall advantage." (emphasis added). As Chairman Allday stated recently in an address to the Texas Independent Producers and Royalty Owners, "rate design and Canada are not preventing domestic producers from competing".

This conclusion that U.S. and Canadian producers are indeed playing on a level playing field was further underscored by the Department of Energy's witness at the Committee hearing. As Mr. Schroeder pointed out,

> "The Department is aware of the claims of domestic producers. We have given careful consideration to their concerns on several occasions. However, we have found their past claims that Canadian gas was somehow gaining preferential access to U.S. markets over domestic gas to be unsupported".

Mr. Schroeder also made a very important observation during the course of the hearing which may not have been fully appreciated at the time -- U.S. producers and consumers are currently free to negotiate terms and conditions which produce a "larger demand charge and a lower commodity rate". Thus, in the growing arena of direct sale opportunities, the ability of U.S. producers to negotiate terms and conditions equivalent to those undertaken by Canadian producers is undeniable. In fact, IPAC had been advised repeatedly that U.S. Northeast market participants had offered essential identical terms to U.S. producers, but that U.S. producers were not prepared, at that time, to enter into such long-term arrangements. Thus, transportation-only pipelines do not accord a special advantage to one group of producers over another.

In addition to the above observations, IPAC believes it is important to clarify the record with respect to several statements made by IPAA Chairman Hilliard:

(1) On page five of his prepared comments, Mr. Hilliard suggests that Canadian producers were unaware of the costs associated with the Iroquois project when producers voted in favor of gas supply contracts underlying the project. This is incorrect. As further stated on page 23, the clear impression is left by these remarks that the pipeline construction costs have jumped from \$1.2 billion to \$2.6 billion, and further, Canadian producers had not been aware of these true costs at the time they voted in support of these projects. This too is incorrect.

The original TCPL application, at a cost of \$1.2 billion, involved a flow configuration on Great Lakes Transmission Limited and Union Gas Limited facilities in Ontario, the costs which in total were equivalent to the current TCPL only option of \$2.6 billion that now constitutes the existing application. The NEB has jurisdiction only to approve TCPL facilities and, accordingly, had no jurisdiction to approve either the Great Lakes or Union Gas facilities. The original TCPL application to the NEB only covered the construction costs of TCPL facilities and not the two additional portions to the overall system. The total costs have remained essentially static at \$2.6 billion, and Canadian producers were aware of that total cost figure at the time they voted in favor of supplying gas to these projects.

(2) Mr. Hilliard argues on pages 5-6 of his prepared statement that if the NEB adopts rolled-in tolling for the additional costs associated with expanding TransCanada, Canadian consumers will be subsidizing Iroquois. It should be noted that Canada's regulatory regime also operates on a netback basis, whereby transportation costs are deducted from the market clearing "burner tip" or "city gate" prices to determine the producer netback wellhead price. It is not Canadian consumers who will be "subsidizing" Iroquois. Canadian producers using the TCPL system will be sharing the costs of the expanded system equally on the basis of rolled-in tolling methodology as currently and historically used in Canada.

Two additional points should also be noted: (1) in excess of 90% of the producers presently shipping gas on the TCPL system will also be supplying the new gas volumes that will utilize these new facilities, and (2) the TCPL expansion application also includes new facilities for new domestic Canadian volumes, and as a result, the export related facilities represent 79% of the new capacity requested, not the 90% as stated on page five of Mr. Hilliard's remarks. Finally, Mr. Hilliard chooses to ignore the fact that rolled-in tolls is the preferred methodology of the U.S. Federal Energy Regulatory Commission as well as the NEB.

(3) Mr. Hilliard maintains that there is a "systematic denial of marketing opportunities" for domestic producers seeking Canadian customers. (Prepared Statement at page 16) This is not the case. U.S. exports of natural gas to Canada increased exponentially over the last several years, and additional new projects to serve Eastern Canadian markets sponsored by U.S. pipelines have been unveiled only within the last several months. In fact, the National Energy Board moved quickly to approve construction of the St. Clair Pipeline Interconnect in 1988, that has allowed for increased imports of American gas into Canada. IPAC believes this trend is an appropriate response to the increasing integration of the North American natural gas market, on a continental basis, and this is why IPAC has not opposed the increased importation of U.S. gas into Canada.

(4) IPAA Chairman Hilliard states on page 21 of his prepared statement that "FERC and DOE remain free to carry out the mandate under the Natural Gas Act to prevent undue discrimination against domestic gas. The FTA is not a barrier to this statutory duty". IPAC concurs with this interpretation of the relationship between the Free Trade Agreement and the Natural Gas Act. The Free Trade Agreement does not prevent either U.S. or Canadian regulatory authorities from addressing and remedying unduly discriminatory action. IPAA's problem is that (1) the differences in transportation rate design between U.S. and Canadian pipelines are not unduly discriminatory; and (2) the "relief" IPAA has sought would be unduly discriminatory, and thus barred by the FTA.

Senator J. Bennett Johnston
June 8, 1990
Page Five

In conclusion, IPAC's members, like IPAA's members, have suffered as a result of depressed prices. It is a difficult time for the producing sector. IPAC believes that a constructive response to these difficult times is for the producing sectors of North America to work together to achieve the full potential of what promises to be a natural gas decade. IPAC is committed to that process and has initiated dialogue with IPAA in order to further that objective.

IPAC appreciates this opportunity to advise the Committee of its views with respect to the important matters brought before you.

Respectfully,

Norman R. Gish
Chairman

NRG/sw

John E. Watson
Senior Vice President
Governmental & Regulatory Affairs

April 27, 1990

1990 [illegible] -3 PM 4: 39

The Honorable Bennett Johnston
Chairman
Senate Committee on Energy and Natural Resources
364 Senate Dirksen Office Building
Washington, D.C. 20510-6150

RE: Canadian Natural Gas Imports Oversight Hearings
Scheduled for May 3, 1990

Dear Mr. Chairman:

You and the Committee are to be congratulated for announcing oversight hearings on the importation of natural gas from Canada and its impact on domestic production. Since the percentage of U.S. market penetration for Canadian natural gas is projected to double during a time of continuing domestic gas surpluses, government policies affecting the importation of Canadian natural gas are of great concern to the domestic industry.

Domestic producers are particularly concerned that differences in Canadian rate designs have allowed Canadian natural gas to be sold in this country under anti-competitive terms. Additionally, current DOE policies regulating the importation of Canadian natural gas contain "loop holes" to the Natural Gas Act that provide irrebuttable regulatory presumptions in favor of such imports. Moreover, despite the expressed policy of the FERC to move the domestic gas market onto a more level and competitive playing field by imposing open access transportation requirements for domestic gas, the Economic Regulatory Administration (ERA) within the DOE has continued to refuse to require the same open access policies to apply to pipelines built or used to transport Canadian gas.

If pipelines that are used to import Canadian gas do not provide open access transportation, it blocks U.S. natural gas competition on the same pipeline to the same markets. When imported Canadian gas is sold under a fixed variable rate design it artificially makes Canadian gas appear cheaper than competing U.S. gas that is normally sold under a modified fixed variable rate design. Lastly, the establishment and use of regulatory presumptions favoring Canadian natural gas have allowed the ERA to authorize Canadian gas import volumes that would, if used, literally flood U.S. markets with artificially low-priced gas.

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During the passage of the U.S.-Canada Free Trade Agreement, Congress recognized that Canada subsidizes its natural gas production in several ways that grant it a competitive advantage in our markets. Consequently, subsidized and improperly priced Canadian gas is causing the U.S. industry to lose needed capital and jobs, and discourages reserve replacement. These anti-competitive pricing and transportation policies have caused and increasingly will cause unfair losses in market share for this important domestic energy resource, thereby further exacerbating the downturn in the domestic extraction industry.

I submit that these policies are not in the best interests of the United States. I urge the Committee to review in detail the current failure of the DOE to require open access pipelines to transport Canadian imports, and competitive rate designs for all sales of Canadian natural gas within the United States. I also urge the Committee to investigate the use of regulatory "loop holes" that have been created by the DOE to benefit Canadian gas importation.

Thank you for your attention to these important matters.

Yours truly,

John E. Watson

John E. Watson

JEW:nw39

GASP
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ANNE MARIE MUESER
Chairman

June 1, 1990

VIA FEDERAL EXPRESS

The Honorable J. Bennett Johnston
136 Senate Hart Office Building
Washington, DC 20510

Dear Senator Johnston:

GASP Coalition, an association of citizens groups (property owners and consumers) has since 1986 participated actively and in good faith in the various proceedings involving Iroquois before the Federal Energy Regulatory Commission. GASP is not opposed to the use of natural gas or to needed gas pipelines. Throughout the FERC "open season," we consistently supported efforts to achieve a settlement which would maximize service to the northeast at the least cost to the environment and the consumer.

The May 3, 1990, hearing held by the Senate Committee on Energy and Natural Resources, chaired by you, helped to focus attention on key issues in the progress of Iroquois through the regulatory process.

As you no doubt are aware, GASP filed a Motion with the FERC on May 18, 1990, requesting an investigation into ex parte contacts between representatives of the FERC and top officials of Iroquois and certain of its equity partners and shippers. A copy of that Motion is enclosed. In light of the serious nature of these allegations, GASP respectfully requests that the record in the May 3, 1990 hearing, which is to close on June 2, 1990, be held open an additional 30 days to enable consideration of what appear to be serious violations of the public trust by FERC personnel and officials of regulated utilities.

I understand the reluctance of your Committee to take any action which might be construed as undue interference in an agency's consideration of the merits of a pending application. I believe, however, that matters concerning the integrity of that process are explicitly within the jurisdiction of the Senate oversight hearing convened by your Committee to examine the FERC's handling of Iroquois. Since the FERC was created by and in fact acts as an arm of Congress, your Committee has full responsibility and indeed a public duty to ascertain that the FERC's processes are untainted by even the appearance of impropriety. It would be most unfortunate if the record of the May 3, 1990, hearing were to close without giving attention to these matters and without reflecting steps that must be taken to restore public confidence in the regulatory process.

Enclosed also for your information and for the record is a copy of a letter GASP has sent to the New York Public Service Commission regarding material submitted to your Committee. GASP's concerns about inappropriate connections between Iroquois and those charged with protecting the public interest are not confined to federal agencies.

In conclusion, I urge you to keep the record of the May 3, 1990, hearing open to enable it to reflect full inquiry into these matters.

Respectfully submitted,

Anne Marie Mueser

Anne Marie Mueser
Chairman, GASP Coalition

AMM/ts
enclosures:
- (1) Motion of GASP Coalition and Anne Marie Mueser for Investigation to Determine Scope of Ex Parte Contacts and to Impose Sanctions (May 18, 1990)
- (2) Letter to Secretary Kelliher, NY PSC, May 29, 1990
- (3) Related press clippings